Energy Vision

2020

8

Volume 2, Technical Document

Resource Integration

Volume 2, Technical Document 8

Resource Integration

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This technical document has eight major sections that were originally separate information items. These were used in various discussions on the resource integration process that TVA used to develop Energy Vision 2020.

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Resource Integration

STRATEGY MATRICES

The Strategy Matrices are detailed descriptions of the supply-side, environmental, customer service, and transmission improvement options contained in each strategy. The first strategy matrix, *Figure T8-1*, depicts how the initial strategies were formed from a list of customer service, supply-side expansion, and nuclear refinement strategies. By analyzing how each strategy behaves under key uncertainties, some strategies were eliminated and some new ones were created. In the second strategy matrix, *Figure T8-2*, many new strategies were formed to provide more flexibility to Energy Vision 2020, TVA's Integrated Resource Plan (IRP). The third strategy matrix, *Figure T8-3*, represents the final strategies that were evaluated in order to develop the Energy Vision 2020 portfolio.

FIGURE T8-1. Strategy Matrix for Year 2010

18-JAN-95

Acronym Key:
BFN Browns Ferry Nuclear Plant
BLN Bellefonte Nuclear Plant
CC Natural Gas Combined Cycle
CT Combustion Turbine
IGCC Integrated Gasification Combined Cycle
IPP Independent Power Producer
WBN Watts Bar Nuclear Plant
CO2 Carbon Dioxide
SO2 Sulfur Dioxide

	SUPPLY PROFILE						ENVIRONMENT		
	Nuclear (MW)	Coal (MW)	Natural Gas (MW)	Hydro & Storage (MW)	Renewables (MW)	Purchased Power (MW)	Clean Air Strategy	Biomass Cofiring	CO_2 Dispatch
Existing System in 1996	5577	14968	2292	5498	0	2300			
Existing System in 2010	5577	14968	2292	5498	0	1100			
Changes from Existing System									
Reference CC/IPP/Coal with Low-Price DSM	0	1155	5930	0	0	1740	Reference	No	No
Customer Service Strategies									
1 CC/IPP/Coal with No DSM	0	1575	6720	0	0	1740	Reference	No	No
2 CC/IPP/Coal with Block 1 DSM	0	1890	5310	0	0	1440	Reference	No	No
3 CC/IPP/Coal with Blocks 1 & 2 DSM	0	1155	4840	0	0	720	Reference	No	No
4 CC/IPP/Coal with Blocks 1, 2, & 3 DSM	0	735	4520	0	0	0	Reference	No	No
5 CC/IPP/Coal with Low-Price DSM	0	1155	5930	0	0	1740	Reference	No	No
6 CC/IPP/Coal with Low BE	0	1890	6570	0	0	1740	Reference	No	No
7 CC/IPP/Coal with High BE	0	1890	6720	0	0	1740	Reference	No	No
Supply-Side Expansion Strategies									
1 Coal Expansion	0	5168	3600	0	0	0	Reference	No	No
2 CC/Coal Expansion	0	1890	6890	0	0	0	Reference	No	No
3 CC Renewable Expansion	0	0	7490	0	1700	0	Reference	No	No
4 CC and IPP Expansion	0	0	6250	0	0	2520	Reference	No	No
Nuclear Refinement Strategies									
1 Defer WBN/BFN and Build	2235	735	4690	0	0	1140	Reference	No	No
2 Defer WBN/BFN and Cancel	0	1890	5010	0	0	1860	Reference	No	No
3 Defer BLN and Build	2424	0	5010	0	0	1440	Reference	No	No
4 Defer BLN and Cancel	0	1155	4990	0	0	1440	Reference	No	No
5 Convert BLN to CC	0	1575	6590	0	0	720	Reference	No	No
6 Partner BLN as Nuclear	1212	1155	5610	0	0	2040	Reference	No	No
7 Partner BLN as IGCC/Coproduct	0	1890	5010	0	0	1924	Reference	No	No
8 Convert BLN to IGCC/Coproduct	0	2520	5140	0	0	1140	Reference	No	No
9 Cancel Four Nuclear Units	0	1890	5010	0	0	1860	Reference	No	No
10 Cancel Three Nuclear Units/Build WBN 2	1170	1890	5010	0	0	720	Reference	No	No
Mixed Strategies									
1 Minimum Debt, Purchases/IPP/IPP Expansion	0	24	3750	0	0	5380	Fuel Switch	No	No
7 Low-Cost Producer 1, CC/IPP/Coal Expansion	0	1890	4710	163	0	1140	Reference	No	No
8 Low-Cost Producer 2, Coal/Coal Expansion	0	4253	3800	163	0	0	Reference	No	No
10 Max "Customer Value Index" (Off-Sys Sales, High BE, Declining Blk)	0	2933	4050	163	0	0	Reference	0.3%	No
11 Low TRC, Coal Expansion, and High DSM	0	1155	3900	163	0	0	Reference	0.3%	No
12 Max. Sales, Coal and Stor. Expn, High Off-Sys Sales	0	1613	7392	668	0	0	Reference	No	No
14 Competitive 1	0	1575	4880	1	0	2460	Reference	No	No
15 Competitive 2	0	1575	7190	1	0	1560	Reference	No	No
2 Min CO_2, Natural Gas Repowering	0	-1931	8850	163	0	0	Repowering	1.3%	Yes
3 Min CO_2, Nat Gas Repowering, & Renewables	0	-1931	4665	163	2240	0	Repowering	1.3%	Yes
4 Max Conservation	0	0	3876	163	0	1200	Reference	0.3%	No
5 Green Strategy, Waste Methane, Wind, & Solar	0	-1931	4721	668	3500	0	Repowering	0.3%	Yes
6 Renew, Waste Methane, Wind, Solar, & Biomass	0	-1931	3971	668	5740	0	Repowering	0.3%	Yes
13 Distributed Generation, CC, Cogen, IPP, & Fuel Cells	0	0	6310	0	500	3300	Reference	No	No
16 Maximum Diversity	0	1155	4676	506	700	1560	Reference	1.3%	No
17 Environmental Sustainability	0	-2609	8181	1011	300	0	Repowering	1.3%	Yes

Notes:
1. The reference strategy, cancel BLN 1 & BLN 2, defer and cancel WBN 2 and BFN 1 with a CC, IPP, coal expansion with low-price DSM provides common point for trade-off plots.
2. Reference clean air strategy is scrub Paradise Unit 3 and Allen Units 1-3 with various fuel switches.
3. Repowering clean air strategy is natural gas combined cycle repowering of Johnsonville and Allen units.
4. Fuel switching clean air strategy is switch to low sulfur coal at most plants and switch to natural gas at Allen.
5. Renewables include solar, wind, short rotation woody crops (SRWC), refuse-derived fuel (RDF), and methane options.

Initial strategies were formed from a list of customer service, supply-side expansion, and nuclear refinement options.

	CUSTOMER SERVICE, PRICING/RATES					TRANSMISSION
	DSM (MW)	Off Sys. Sales (MW)	Beneficial Electrification (MW)	Pricing (Time-of-Day/ Declining Block) (MW)	Price Feedback (MW)	Transmission Improvements
	-1120	0	0	0	138	No
	0	0	0	0	112	No
	-1365	0	0	0	23	No
	-2997	0	0	0	191	No
	-4183	0	0	0	302	No
	-1120	0	0	0	138	No
	0	0	89	0	203	No
	0	0	196	0	103	No
	-1122	0	0	0	112	No
	-1122	0	0	0	23	No
	-1120	0	0	0	191	No
	-1119	0	0	0	302	No
	-1118	0	0	0	-160	No
	-1119	0	0	0	55	No
	-1118	0	0	0	-112	No
	-1120	0	0	0	83	No
	-1120	0	0	0	201	No
	-1120	0	0	0	246	No
	-1122	0	0	0	711	No
	-1123	0	0	0	892	No
	-1119	0	0	0	95	No
	-1120	0	0	0	410	No
	0	0	0	-892	-1137	No
	-1118	1000	144	-892	297	No
	-1120	1000	144	-892	767	No
	-2930	0	196	169	670	No
	-4185	0	0	0	395	No
	0	2000	0	0	1007	Yes
	-1118	0	0	0	-50	No
	0	0	196	0	-27	No
	-4180	0	0	0	35	No
	-4187	0	0	0	535	Yes
	-4183	0	0	0	276	Yes
	-4487	0	0	0	596	No
	-4468	0	0	0	256	No
	0	0	0	0	-331	No
	-1118	0	76	0	110	No
	-4178	0	0	0	-87	No

FIGURE T8-2. Strategy Matrix for Years 2005 and 2020

09-MAR-95

Acronym Key:
BFN Browns Ferry Nuclear Plant
BLN Bellefonte Nuclear Plant
CC Natural Gas Combined Cycle
CT Combustion Turbine
IGCC Integrated Gasification Combined Cycle
IPP Independent Power Producer
WBN Watts Bar Nuclear Plant
CO2 Carbon Dioxide
SO2 Sulfur Dioxide

		SUPPLY PROFILE						ENVIRONMENT			CUSTOMER SERVICE, PRICING/RATES				
	Year	Nuclear (MW)	Coal (MW)	Natural Gas (MW)	Hydro & Storage (MW)	Renewables (MW)	Purchased Power (MW)	Clean Air Strategy	Biomass Cofiring	CO_2 Dispatch	DSM (MW)	Off Sys. Sales (MW)	Beneficial Electrification (MW)	Pricing (Time-of-Day/ Declining Block) (MW)	Price Feedback (MW)
Existing System in 2005		5577	14968	2292	5498	0	1800								
Existing System in 2020		5577	14968	2292	5498	0	1000								
Changes From Existing System															
2 Min CO_2 - (Nat Gas Repowering	2005	0	-1931	4835	0	0	0	Repowering	1.3%	Yes	-3171	0	0	0	-147
of Existing Coal)	2020	0	-1931	14300	162	0	0	Repowering	1.3%	Yes	-1480	0	0	0	-1990
3 Min CO_2 - (Nat Gas Repowering	2005	0	-1931	3765	0	740	0	Repowering	1.3%	Yes	-3172	0	0	0	-85
of Existing Coal & Renewables)	2020	0	-1931	11265	162	3840	0	Repowering	1.3%	Yes	-1480	0	0	0	-1347
8 Low-Cost Producer	2005	0	2378	2400	0	0	0	Reference	No	No	-999	1000	62	-796	367
(Coal-Based)	2020	0	9053	5400	162	0	0	Reference	No	No	-517	0	25	-1043	-216
9 Reference (Combined Cycle,	2005	0	0	4430	0	0	925	Reference	No	No	-997	0	0	0	57
Purchased Power, Coal)	2020	0	5775	8520	0	0	1225	Reference	No	No	-517	0	0	0	-596
10 Max "Customer Value Index" (Off-	2005	0	2978	2700	0	0	0	Reference	0.3%	No	-997	1000	180	167	242
Sys Sales, High BE, Declining Blk)	2020	0	9953	5850	162	0	0	Reference	0.3%	No	-517	0	71	169	-237
11 Low TRC/High DSM	2005	0	300	2250	0	0	0	Reference	0.3%	No	-3169	0	0	0	-268
	2020	0	7230	5550	162	1500	0	Reference	0.3%	No	-1480	0	0	0	-437
12 Maximum Sales	2005	0	878	5820	0	0	0	Reference	0.3%	No	0	1000	180	0	493
	2020	0	5078	10474	162	0	0	Reference	0.3%	No	0	0	71	0	-385
16 Maximum Capacity Diversity	2005	0	0	3902	0	0	625	Reference	1.3%	No	-999	0	62	0	122
	2020	0	5355	6122	162	1640	775	Reference	1.3%	No	-517	0	25	0	-629
18 Bellefonte Nuclear Partnership	2005	600	0	3960	0	0	775	Reference	1.3%	No	-998	0	0	0	55
	2020	600	5775	8050	0	0	1075	Reference	1.3%	No	-516	0	0	0	-542
20 Bellefonte Coproduct and	2005	0	0	2550	0	500	2284	Reference	0.3%	No	-997	0	0	0	330
Renewables	2020	0	5775	5850	162	1500	2584	Reference	0.3%	No	-517	0	0	0	184
23 Defer and Build BFN 1 and WBN 2	2005	1170	0	3510	0	0	775	Reference	No	No	-997	0	0	0	-285
with Reference Expansion	2020	2235	5355	6810	0	0	775	Reference	No	No	-517	0	0	0	-774
24 Minimize CO_2 with Less DSM	2005	0	-1931	5110	0	740	0	Repowering	1.3%	Yes	-2048	0	0	0	180
	2020	0	-1931	11735	162	3640	0	Repowering	1.3%	Yes	-958	0	0	0	-1384
28 Combined DSM and	2005	0	1778	2400	0	0	0	Reference	0.3%	No	-2047	1000	0	0	229
Off-Sys Sales	2020	0	7553	5700	162	1500	0	Reference	0.3%	No	-957	0	0	0	-274
29 Decentralized Generation	2005	0	0	4430	160	0	775	Reference	No	No	-998	0	0	0	90
with More Renewables	2020	0	0	10860	160	1900	925	Reference	No	No	-517	0	0	0	-1707
32 Bellefonte Coproduct, More DSM,	2005	0	0	2550	0	500	1384	Reference	0.3%	No	-2049	1000	0	0	454
and More Off-Sys Sales	2020	0	6510	5700	162	1500	1534	Reference	0.3%	No	-958	0	0	0	275
34 Low-Cost Renewables,	2005	0	-1931	5284	1011	740	450	Repowering	0.3%	Yes	-998	0	0	0	235
Low-Price DSM, Repowering	2020	0	2307	8115	1173	3340	450	Repowering	0.3%	Yes	-517	0	0	0	-253
39 Flexible Strategy with	2005	0	0	900	0	1000	3773	Reference	0.3%	No	-999	1000	62	0	648
External Options	2020	0	7665	4800	162	1500	1973	Reference	0.3%	No	-517	0	25	0	402
40 Flexible Strategy with	2005	0	0	2570	0	1250	1973	Reference	0.3%	No	-999	1000	62	0	583
Internal Options	2020	0	7665	5720	162	1500	1673	Reference	0.3%	No	-517	0	25	0	454
41 Low Cost, Low Rates,	2005	0	0	2850	0	1250	1534	Reference	0.3%	No	-999	1000	62	0	493
Improved Environment	2020	0	6930	5850	162	1500	1534	Reference	0.3%	No	-517	0	25	0	369

Notes:
1. The reference strategy, cancel BLN 1 & BLN 2, defer and cancel WBN 2 and BFN 1 with a CC, IPP, coal expansion with low-price DSM provides common point for trade-off plots.
2. Reference clean air strategy is scrub Paradise Unit 3 and Allen Units 1-3 with various fuel switches.
3. Repowering clean air strategy is natural gas combined cycle repowering of Johnsonville and Allen units.
4. Fuel switching clean air strategy is switch to low sulfur coal at most plants and switch to natural gas at Allen.
5. Renewables include solar, wind, short rotation woody crops (SRWC), refuse-derived fuel (RDF), and methane options.
6. Off-system sales begin in 1996 and end in 2004.
7. Strategies 3 and 12 contain additional transmission system capital and efficiency improvements.

New strategies were formed to provide more flexibility to TVA's Integrated Resource Plan.

TRANSMISSION	CAPACITY AND ENERGY BY FUEL TYPE											
Transmission Improvements	Nuclear (MW)	Nuclear (GWH)	Coal (MW)	Coal (GWH)	Natural Gas (MW)	Natural Gas (GWH)	Hydro & Storage (MW)	Hydro & Storage (GWH)	Renewables (MW)	Renewables (GWH)	Purchased Power (MW)	Purchased Power (GWH)
	5577	30171	14968	96212	2292	1009	5498	19268	0	0	1800	
	5577	32414	14968	100654	2292	1403	5498	20780	740	5898.5	1000	
		(CF)		(CF)		(CF)		(CF)		(CF)		(CF)
Yes	5577	67.1%	13037	84.2%	7127	20.4%	5498	42.4%	0	0	1800	4.4%
Yes	5577	67.1%	13037	85.1%	16592	39.1%	5660	42.1%	0	0	1000	0.6%
Yes	5577	67.1%	13037	82.9%	6057	16.4%	5498	42.4%	740	91.0%	1800	4.1%
Yes	5577	67.1%	13037	84.9%	13557	34.1%	5660	42.1%	3640	62.7%	1000	1.1%
No	5577	67.1%	17346	80.5%	4692	11.7%	5498	42.4%	0	0	1800	7.5%
No	5577	67.1%	24021	79.0%	7692	9.7%	5660	42.1%	0	0	1000	1.0%
No	5577	67.1%	14968	82.8%	6722	13.2%	5498	42.4%	0	0	2725	26.0%
No	5577	67.1%	20743	82.2%	10812	11.2%	5498	43.3%	0	0	2225	35.2%
No	5577	67.1%	17946	77.8%	4992	7.9%	5498	42.4%	0	0	1800	4.7%
No	5577	67.1%	24921	75.8%	8142	6.8%	5660	42.1%	0	0	1000	1.1%
No	5577	67.1%	15268	78.5%	4542	7.5%	5498	42.4%	0	0	1800	5.3%
No	5577	67.1%	22198	75.1%	7842	8.1%	5660	42.1%	1500	94.1%	1000	0.7%
Yes	5577	67.1%	15846	83.5%	8112	19.5%	5498	42.4%	0	0	1800	4.0%
Yes	5577	67.1%	20046	83.7%	12766	21.0%	5660	42.2%	0	0	1000	0%
No	5577	67.1%	14968	83.2%	6194	18.4%	5498	42.4%	0	0	2425	24.6%
No	5577	67.1%	20323	82.4%	8414	16.0%	5660	42.2%	1640	28.6%	1775	30.3%
No	6177	67.9%	14968	81.5%	6252	11.5%	5498	42.4%	0	0	2575	41.4%
No	6177	67.9%	20743	81.4%	10342	10.5%	5498	43.3%	0	0	2075	54.4%
No	5577	67.1%	14968	81.3%	4842	6.4%	5498	42.4%	500	94.1%	4084	27.5%
No	5577	67.1%	20743	80.0%	8142	6.4%	5660	42.1%	1500	94.1%	3584	28.4%
No	6747	63.7%	14968	79.8%	5802	9.2%	5498	42.4%	0	0	2575	21.9%
No	7812	67.1%	20323	79.1%	9102	9.4%	5498	43.3%	0	0	1775	29.1%
No	5577	67.1%	13037	84.4%	7402	22.7%	5498	42.4%	740	91.0%	1800	5.2%
No	5577	67.1%	13037	85.0%	14027	35.3%	5660	42.1%	3640	62.4%	1000	1.1%
No	5577	67.1%	16746	78.0%	4692	7.3%	5498	42.4%	0	0	1800	4.7%
No	5577	67.1%	22521	75.7%	7992	6.7%	5660	42.1%	1500	94.1%	1000	0.8%
No	5577	67.1%	14968	82.7%	6722	13.4%	5658	43.0%	0	0	2575	24.4%
No	5577	67.1%	14968	84.7%	13172	29.7%	5658	44.3%	1900	59.1%	1925	28.0%
No	5577	67.1%	14968	80.5%	4842	6.9%	5498	42.4%	500	94.1%	3184	24.5%
No	5577	67.1%	21478	77.9%	7992	6.6%	5660	42.1%	1500	94.1%	2534	26.6%
No	5577	67.1%	13037	84.5%	7576	25.0%	6509	35.8%	740	91.0%	2250	22.4%
No	5577	67.1%	17275	83.6%	10407	22.9%	6671	35.7%	3340	63.3%	1450	23.3%
No	5577	67.1%	14968	81.3%	3192	5.3%	5498	42.4%	1000	94.1%	5573	22.8%
No	5577	67.1%	22633	76.3%	7092	6.7%	5660	42.1%	1500	94.1%	2973	20.0%
No	5577	67.1%	14968	80.6%	4862	7.2%	5498	42.4%	1250	94.1%	3773	24.5%
No	5577	67.1%	22633	76.4%	8012	6.4%	5660	42.1%	1500	94.1%	2673	21.6%
No	5577	67.1%	14968	80.5%	5142	7.1%	5498	42.4%	1250	94.1%	3334	25.6%
No	5577	67.1%	21898	78.0%	8142	6.8%	5660	42.1%	1500	94.1%	2534	26.9%

FIGURE T8-3. Strategy Matrix for Years 2005 and 2020

09-APRIL-95

Acronym Key:
BFN Browns Ferry Nuclear Plant
BLN Bellefonte Nuclear Plant
CC Natural Gas Combined Cycle
CT Combustion Turbine
IGCC Integrated Gasification Combined Cycle
IPP Independent Power Producer
WBN Watts Bar Nuclear Plant
CO2 Carbon Dioxide
SO2 Sulfur Dioxide

		Year	SUPPLY PROFILE: Nuclear (MW)	Coal (MW)	Natural Gas (MW)	Hydro & Storage (MW)	Renewables (MW)	Purchased Power (MW)	ENVIRONMENT: Clean Air Strategy	Biomass Cofiring	CO_2 Dispatch	CUSTOMER SERVICE, PRICING/RATES: DSM (MW)	Off Sys. Sales (MW)	Beneficial Electrification (MW)	Pricing (Time-of-Day/ Declining Block) (MW)	Price Feedback (MW)
Existing System in 2005			5577	14968	2292	5498	0	1800								
Existing System in 2020			5577	14968	2292	5498	0	1000								
Changes from Existing System																
A	2 Min CO_2 - (Nat Gas Repowering	2005	0	-1931	4695	0	0	0	Repowering	1.3%	Yes	-3171	0	0	0	-187
	of Existing Coal)	2020	0	-1931	14425	162	0	0	Repowering	1.3%	Yes	-1480	0	0	0	-1810
B	3 Min CO_2 - (Nat Gas Repowering	2005	0	-1931	3765	0	740	0	Repowering	1.3%	Yes	-3172	0	0	0	-126
	of Existing Coal & Renewables)	2020	0	-1931	12150	162	3040	0	Repowering	1.3%	Yes	-1480	0	0	0	-1147
C	8 Low-Cost Producer	2005	0	2378	2400	0	0	0	Reference	No	No	-999	1000	62	-796	330
	(Coal-Based)	2020	0	9053	5400	162	0	0	Reference	No	No	-517	0	25	-1043	-254
D	9 Reference (Combined Cycle,	2005	0	0	4430	0	0	925	Reference	No	No	-997	0	0	0	20
	Purchased Power, Coal)	2020	0	5775	8520	0	0	1225	Reference	No	No	-517	0	0	0	-620
E	10 Max "Customer Value Index" (Off-	2005	0	2978	2700	0	0	0	Reference	0.3%	No	-997	1000	180	167	203
	Sys Sales, High BE, Declining Blk)	2020	0	10388	5850	162	0	0	Reference	0.3%	No	-517	0	71	169	-313
F	11 Low TRC/High DSM	2005	0	300	2250	0	0	0	Reference	0.3%	No	-3169	0	0	0	-302
		2020	0	7230	5550	162	1500	0	Reference	0.3%	No	-1480	0	0	0	-468
G	12 Maximum Sales	2005	0	878	5820	0	0	0	Reference	0.3%	No	-1	1000	180	0	461
		2020	0	5498	9242	1173	0	0	Reference	0.3%	No	0	0	71	0	-341
H	16 Maximum Capacity Diversity	2005	0	0	3380	1011	60	775	Reference	1.3%	No	-999	0	62	0	95
		2020	0	4620	5410	2185	1740	925	Reference	1.3%	No	-517	0	25	0	-701
I	18 Bellefonte Nuclear Partnership	2005	600	0	3960	0	0	775	Reference	1.3%	No	-998	0	0	0	55
		2020	600	5775	8050	0	0	1075	Reference	1.3%	No	-516	0	0	0	-542
J	20 Bellefonte Coproduct and	2005	0	484	2550	0	750	1650	Reference	0.3%	No	-998	0	0	0	318
	Renewables	2020	0	6994	5850	162	1500	1950	Reference	0.3%	No	-517	0	0	0	230
K	23 Defer and Build BFN 1 & WBN 2	2005	1170	0	3510	0	0	775	Reference	No	No	-997	0	0	0	-323
	with Reference Expansion	2020	2235	5355	6810	0	0	775	Reference	No	No	-517	0	0	0	-799
L	24 Minimize CO_2 with Less DSM	2005	0	-1931	5110	0	740	0	Repowering	1.3%	Yes	-2048	0	0	0	144
		2020	0	-1931	12770	162	2840	0	Repowering	1.3%	Yes	-958	0	0	0	-1191
M	28 Combined DSM and	2005	0	1778	2400	0	0	0	Reference	0.3%	No	-2047	1000	0	0	188
	Off-Sys Sales	2020	0	7553	5550	162	1500	0	Reference	0.3%	No	-957	0	0	0	-317
N	29 Decentralized Generation with	2005	0	0	3960	160	0	775	Reference	No	No	-998	0	0	0	39
	More Renewables	2020	0	0	10860	160	1900	925	Reference	No	No	-517	0	0	0	-1596
O	32 Bellefonte Coproduct, More DSM,	2005	0	484	2550	0	500	900	Reference	0.3%	No	-2049	1000	0	0	428
	and More Off-Sys Sales	2020	0	6994	5700	162	1500	1050	Reference	0.3%	No	-958	0	0	0	263
P	34 Low-Cost Renewables,	2005	0	-1931	6105	0	740	300	Repowering	0.3%	Yes	-998	0	0	0	203
	Low-Price DSM, Repowering	2020	0	207	11025	1174	2090	450	Repowering	0.3%	Yes	-517	0	0	0	-771
Q	39 Flexible Strategy with	2005	0	484	900	0	1000	3289	Reference	0.3%	No	-999	1000	62	0	648
	External Options	2020	0	8149	4800	162	1500	1489	Reference	0.3%	No	-517	0	25	0	402
R	40 Flexible Strategy with	2005	0	484	2570	0	1000	1489	Reference	0.3%	No	-999	1000	62	0	583
	Internal Options	2020	0	8149	5420	162	1500	1489	Reference	0.3%	No	-517	0	25	0	454
S	41 Low Cost, Low Rates,	2005	0	484	2850	0	1250	1050	Reference	0.3%	No	-999	1000	62	0	493
	Improved Environment	2020	0	7414	5850	162	1500	1050	Reference	0.3%	No	-517	0	25	0	369
T	44 Low-Cost Renew, Low-Price DSM,	2005	0	-1447	6225	0	0	450	Repowering	0.3%	Yes	-998	0	0	0	390
	Repowering, BLN Coproduct Part	2020	0	691	10750	1174	2500	450	Repowering	0.3%	Yes	-517	0	0	0	-55
U	45 Low-Cost Renewables, More DSM,	2005	0	-1447	5145	0	0	300	Repowering	0.3%	Yes	-2048	0	0	0	252
	Repowering, BLN Coproduct Part	2020	0	691	10750	1174	2100	450	Repowering	0.3%	Yes	-957	0	0	0	-12

Notes:
1. The reference strategy, cancel BLN 1 & BLN 2, defer and cancel WBN 2 and BFN 1 with a CC, IPP, coal expansion with low-price DSM provides common point for trade-off plots.
2. Reference clean air strategy is scrub Paradise Unit 3 and Allen Units 1-3 with various fuel switches.
3. Repowering clean air strategy is natural gas combined cycle repowering of Johnsonville and Allen units.
4. Fuel switching clean air strategy is switch to low sulfur coal at most plants and switch to natural gas at Allen.
5. Renewables include solar, wind, short rotation woody crops (SRWC), refuse-derived fuel (RDF), and methane options.
6. Off-system sales begin in 1996 and end in 2004.
7. Strategies 3 and 12 contain additional transmission system capital and efficiency improvements.

This table details the final strategies that were evaluated to develop TVA's portfolio of resource options.

TRANSMISSION	CAPACITY AND ENERGY BY FUEL TYPE											
Transmission Improvements	Nuclear (MW)	Nuclear (GWH)	Coal (MW)	Coal (GWH)	Natural Gas (MW)	Natural Gas (GWH)	Hydro & Storage (MW)	Hydro & Storage (GWH)	Renewables (MW)	Renewables (GWH)	Purchased Power (MW)	Purchased Power (GWH)
	5577	30171	14968	96212	2292	1009	5498	19268	0	0	1800	
	5577	32414	14968	100654	2292	1403	5498	20780	740	5898.5	1000	
		(CF)		(CF)		(CF)		(CF)		(CF)		(CF)
Yes	5577	67.1%	13037	84.2%	6987	20.7%	5498	42.4%	0	0	1800	3.4%
Yes	5577	67.1%	13037	85.1%	16717	39.5%	5660	42.1%	0	0	1000	0.7%
Yes	5577	67.1%	13037	82.9%	6057	16.1%	5498	42.4%	740	91.0%	1800	4.0
Yes	5577	67.1%	13037	85.0%	14442	34.2%	5660	42.1%	3040	69.4%	1000	0.3%
No	5577	67.1%	17346	80.4%	4692	11.5%	5498	42.4%	0	0	1800	7.5%
No	5577	67.1%	24021	78.9%	7692	9.6%	5660	42.1%	0	0	1000	1.0%
No	5577	67.1%	14968	82.7%	6722	13.0%	5498	42.4%	0	0	2725	25.8%
No	5577	67.1%	20743	82.2%	10812	11.1%	5498	43.3%	0	0	2225	35.1%
No	5577	67.1%	17946	77.8%	4992	7.7%	5498	42.4%	0	0	1800	4.7%
No	5577	67.1%	25356	74.6%	8142	5.8%	5660	42.1%	0	0	1000	0.8%
No	5577	67.1%	15268	78.4%	4542	7.4%	5498	42.4%	0	0	1800	5.2%
No	5577	67.1%	22198	75.0%	7842	6.0%	5660	42.1%	1500	94.1%	1000	0.7%
Yes	5577	67.1%	15846	83.4%	8112	19.4%	5498	42.4%	0	0	1800	3.9%
Yes	5577	67.1%	20466	83.9%	11534	17.4%	6671	42.2%	0	0	1000	0
No	5577	67.1%	14968	83.6%	5672	12.8%	6509	41.0%	60	87.7%	2575	25.6%
No	5577	67.1%	19588	84.1%	7702	11.7%	7683	41.1%	1740	28.7%	1925	32.5%
No	6177	67.9%	14968	81.5%	6252	11.5%	5498	42.4%	0	0	2575	23.8%
No	6177	67.9%	20743	81.4%	10342	10.5%	5498	43.3%	0	0	2075	32.6%
No	5577	67.1%	15452	81.3%	4842	5.9%	5498	42.4%	750	94.1%	3450	17.4%
No	5577	67.1%	21962	78.7%	8142	5.3%	5660	42.1%	1500	94.1%	2950	15.4%
No	6747	63.7%	14968	79.8%	5802	9.0%	5498	42.4%	0	0	2575	21.9%
No	7812	67.1%	20323	79.1%	9102	9.3%	5498	43.3%	0	0	1775	29.1%
No	5577	67.1%	13037	84.3%	7402	22.7%	5498	42.4%	740	91.0%	1800	5.2%
No	5577	67.1%	13037	85.0%	15062	35.3%	5660	42.1%	2840	71.9%	1000	0
No	5577	67.1%	16746	77.9%	4692	7.1%	5498	42.4%	0	0	1800	4.6%
No	5577	67.1%	22521	75.6%	7842	6.7%	5660	42.1%	1500	94.1%	1000	0.9%
No	5577	67.1%	14968	82.6%	6252	13.8%	5658	43.0%	0	0	2575	25.1%
No	5577	67.1%	14968	84.7%	13152	30.0%	5658	44.3%	1900	59.1%	1925	30.0%
No	5577	67.1%	15452	80.6%	4842	6.8%	5498	42.4%	500	94.1%	2700	13.4%
No	5577	67.1%	21962	78.1%	7992	6.5%	5660	42.1%	1500	94.1%	2050	12.7%
No	5577	67.1%	13037	84.5%	8397	24.0%	5498	42.4%	740	91.0%	2100	17.3%
No	5577	67.1%	15175	84.8%	13317	28.0%	6672	43.4%	2090	75.1%	1450	26.7%
No	5577	67.1%	15452	81.4%	3192	5.2%	5498	42.4%	1000	94.1%	5089	16.7%
No	5577	67.1%	23117	76.4%	7092	6.7%	5660	42.1%	1500	94.1%	2489	7.2%
No	5577	67.1%	15452	81.4%	4862	8.1%	5498	42.4%	1000	94.1%	3289	17.3%
No	5577	67.1%	23117	76.5%	7712	6.4%	5660	42.1%	1500	94.1%	2489	6.9%
No	5577	67.1%	15452	80.6%	5142	7.0%	5498	42.4%	1250	94.1%	2850	15.3%
No	5577	67.1%	22382	78.1%	8142	6.7%	5660	42.1%	1500	94.1%	2050	13.0%
No	5577	67.1%	13521	84.7%	8517	26.9%	5498	42.4%	0	0	2250	19.7%
No	5577	67.1%	15659	84.8%	13042	27.7%	6672	43.3%	2500	69.0%	1450	26.5%
No	5577	67.1%	13521	84.6%	7437	23.6%	5498	42.4%	0	0	2100	15.1%
No	5577	67.1%	15659	84.8%	13042	26.9%	6672	43.3%	2100	76.2%	1450	26.6%

RANKING OF OPTIONS

Following is a set of tables showing the ranking of supply-side and customer service options for Energy Vision 2020. The rankings of these options are used to help create the strategies, as shown in the Strategy Matrices *(Figures T8-1* through *T8-3).*

Figures T8-4 through *T8-12* show supply-side options, and *Figures T8-13* through *T8-18* show customer service options. The options are ranked by several key criteria. The criteria used are total resource costs, rate impact measure (RIM), customer value, average short-term rates, average mid-term rates, debt, and environmental characteristics.

All of the options were standardized in the supply-side and customer service options ranking. In the supply-side ranking, the capacity for base and peaking options was standardized to 500 megawatts and 250 megawatts, respectively. In addition, the construction lead time, if greater than seven years, was adjusted to seven years. One unit of either base or peaking was allowed to come on-line in the year 2001. All other system expansion was completed with pulverized coal and combustion turbine plants.

Customer service options were developed in a similar manner. For purposes of ranking, all customer service blocks were standardized at 250 megawatts. Penetration of a customer service block began in the year 1995 and full penetration (250 megawatts) was completed in the year 2005.

This methodology provides a comparison of supply-side and customer service options on an equal basis. However, the ranking results are not comparable to other expansion results in Energy Vision 2020.

The boldface column on each ranking table provides a frame of reference for purposes of comparison among tables.

FIGURE T8-4. **Bellefonte Repowering Options**

Option	Fuel Type	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020		
									SO_2 (Tons)	NO_x (Tons)	CO_2 (KTons)
BLN Repowering - IGCC Coproduction w/ Partners (2x242 MW)	Syn-Gas	86173	51.1	1287	44.8	49.3	30864	34090	521457	437186	139332
BLN Repowering - IGCC Demo w/ Partners (1x250 MW)	Syn-Gas	86460	51.2	1063	44.7	49.3	30572	33812	522020	437360	139053
BLN Repowering - IGCC with Coproduction (11x229 MW)	Coal-Gas	87417	51.7	165	45.0	49.9	31382	34396	520462	436568	139978
BLN Repowering - CC (10x222 MW)	Natural Gas	88158	52.1	-378	44.8	50.3	30478	33326	538600	442571	138940
BLN Repowering - Phased CC/IGCC-Phase A-CC (9x222 MW)	Coal-Gas	88218	52.1	-464	44.9	50.4	30799	33548	529762	439567	138753
BLN Repowering - IGCC (9x250 MW)	Coal-Gas	88241	52.1	-508	45.0	50.4	31011	33744	520248	437839	138586
Supercritical PC Plant (4x300 MW)	**Coal**	**88266**	**52.2**	**-524**	**44.9**	**50.4**	**30942**	**33845**	**524181**	**437457**	**138943**
BLN Repowering - PC (4x616 MW)	Coal	88317	52.2	-569	44.9	50.4	30853	33837	523942	438145	138931

Acronym Key:

BLN Bellefonte Nuclear Plant
CC Natural Gas Combined Cycle
IGCC Integrated Gasification Combined Cycle
PC Pulverized Coal
CO_2 Carbon Dioxide
K Thousands
M Millions
MW Megawatts
MWh Megawatt-Hours
NO_X Nitrogen Oxides
RIM Rate Impact Measure
SO_2 Sulfur Dioxide

FIGURE T8-5. Supply Option Comparison (Base Category / Coal Only)

Option	Fuel Type	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020		
									SO_2 (Tons)	NO_x (Tons)	CO_2 (KTons)
Shawnee Unit 11 (1x168 MW)	Coal	88137	52.1	-363	44.8	50.3	30544	33400	538592	448260	139224
Partially Completed PC Plant (1x710 MW)	Coal	88147	52.1	-389	44.8	50.3	30732	33584	525128	437768	139082
Advanced PFBC - No Development Cost (1x300 MW)	Coal	88232	52.2	-538	44.9	50.5	30879	33682	524977	437396	138291
State-of-the-Art PC Plant (1x400 MW)	Coal	88242	52.1	-502	44.9	50.4	31029	33910	520914	436690	138526
Supercritical PC Plant (4x300 MW)	**Coal**	**88266**	**52.2**	**-524**	**44.9**	**50.4**	**30942**	**33845**	**524181**	**437457**	**138943**
Restart of WBF (1x56 MW)	Coal	88301	52.1	-498	44.8	50.4	30538	33425	542777	447129	139444
Supercritical PC Plant (4x300 MW)	Coal	88303	52.2	-562	44.9	50.4	30980	33874	524141	438198	139054
Advanced PFBC - w/ Development Cost (1x300 MW)	Coal	88316	52.2	-640	44.9	50.6	31030	33779	524359	437180	138198
Unit Power Purchase-15 Year	Coal	88325	52.2	-546	44.7	50.4	30220	33181	533915	443556	138952
Circulating AFBC (1x200 MW)	Coal	88331	52.2	-591	44.9	50.5	31022	33909	523172	437370	138974
First Generation PFBC (1x340 MW)	Coal	88334	52.2	-568	44.9	50.4	30915	33880	523486	437426	138487
AFBC Repowering, Generic (1x125 MW)	Coal	88344	52.2	-619	45.0	50.5	31441	34150	502340	430923	138665
Supercritical PC Plant (1x300 MW)	Coal	88360	52.2	-626	44.9	50.5	31092	33977	524220	437414	138840
First Generation PFBC Repowering (1x156 MW)	Coal	88395	52.2	-667	45.0	50.5	31471	34183	501609	430616	138078
NUG - Generic IPP Lignite CFBC (1x300 MW)	Coal	88429	52.2	-672	44.7	50.7	30182	33159	528976	440190	139098
Lignite-Fired CFBC (1x200 MW)	Coal	88513	52.3	-750	44.9	50.6	31113	34004	537571	442027	139050
NUG - Generic IPP PC w/ Cogeneration (2x170 MW)	Coal	88614	52.3	-780	44.7	50.7	30182	33080	522594	437188	138766
Generic PFBC Cogeneration (1x70 MW)	Coal	89708	52.9	-1728	44.7	51.4	29945	32688	522164	436896	137064

Acronym Key:

AFBC	Atmospheric Fluidized Bed Combustion	NUG	Non-Utility Generation	CO_2	Carbon Dioxide	MWh	Megawatt-Hours
CFBC	Circulating Fluidized Bed Combustion	PC	Pulverized Coal	K	Thousands	NO_X	Nitrogen Oxides
IPP	Independent Power Producer	PFBC	Pressurized Fluidized Bed Combustion	M	Millions	RIM	Rate Impact Measure
		WBF	Watts Bar Fossil Plant	MW	Megawatts	SO_2	Sulfur Dioxide

FIGURE T8-6. Supply Option Comparison (Base Category / Coal-Gas Only)

Option	Fuel Type	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020 SO_2 (Tons)	NO_x (Tons)	CO_2 (KTons)
Coal Refinery/ IGCHAT, Greenfield (1x530 MW)	Coal-Gas	86778	51.4	688	45.1	49.5	31822	34583	520817	437042	139173
Coal Refinery/IGCC, Greenfield (1x530 MW)	Coal-Gas	86881	51.5	581	45.1	49.6	31934	34730	520747	437046	139067
IGCC w/ Coproduction, Greenfield (1x498 MW)	Coal-Gas	87527	51.8	24	45.1	50.0	31609	34506	520424	437379	139462
IGCHAT w/ Coproduction, Greenfield (1x598 MW)	Coal-Gas	87590	51.8	0	45.0	50.0	31386	34336	520567	437361	139258
IGCHAT w/ Coproduction, F-CT (2x203 MW)	Coal-Gas	87638	51.8	25	45.0	49.9	31338	34273	520592	436206	139776
IGCHAT w/ Coproduction, G-CT (2x420 MW)	Coal-Gas	87790	51.9	-96	44.9	50.0	31211	34032	521038	436376	139672
IGCC w/ Fertilizer Coproduction (3x227 MW)	Coal-Gas	87910	52.0	-238	45.0	50.2	31454	34282	520600	436519	138632
IGCHAT, G-CT (2x420 MW)	Coal-Gas	88138	52.1	-396	44.9	50.3	30856	33679	520295	436050	138591
Coalbed Methane (1x2 MW)	Coal-Gas	88141	52.1	-355	44.7	50.3	30846	33743	518427	437149	137012
IGCHAT, F-CT (2x303 MW)	Coal-Gas	88189	52.1	-449	44.9	50.4	30922	33686	520335	436063	138708
Partnered IGCC w/Coproduction, Greenfield (1x530MW)	Coal-Gas	88193	52.1	-421	44.8	50.4	30550	33318	538769	442732	138934
IGCC (3x245 MW)	Coal-Gas	88237	52.1	-507	44.9	50.4	31023	33900	520107	436280	138182
Supercritical PC Plant (4x300 MW)	**Coal**	**88266**	**52.2**	**-524**	**44.9**	**50.4**	**30942**	**33845**	**524181**	**437457**	**138943**
NUG-Generic IPP IGCC (1x110 MW)	Coal-Gas	88990	52.5	-1104	44.6	50.9	29927	32988	538026	442356	138404
Coal-Gas - Repowering / Conversion Options											
Repower ALF w/ IGCC (1x500 MW)	Coal-Gas	88364	52.2	-549	44.9	50.4	30919	33749	520946	436546	138459
Repower WBF w/ IGCC (1x242 MW)	Coal-Gas	88497	52.2	-675	44.9	50.5	31039	33828	520628	436447	138561
Repower JOF 1-6 w/ IGCC (1x242 MW)	Coal-Gas	88549	52.3	-747	45.0	50.6	31312	34027	508182	432744	138203
Repower JOF 7-10 w/ IGCC (1x250 MW)	Coal-Gas	88590	52.3	-764	45.1	50.6	31262	33982	505874	432131	138026

Acronym Key:

ALF	Allen Fossil Plant	IGCC	Integrated Gasification Combined Cycle	PC	Pulverized Coal	MWh	Megawatt-Hours
CC	Natural Gas Combined Cycle	IGCHAT	Integrated Gasification Cascaded Humidified Advanced Turbine	WBF	Watts Bar Fossil Plant	NO_X	Nitrogen Oxides
CHAT	Cascaded Humidified Advanced Turbine	IPP	Independent Power Producer	CO_2	Carbon Dioxide	RIM	Rate Impact Measure
CT	Combustion Turbine	JOF	Johnsonville Fossil Plant	K	Thousands	SO_2	Sulfur Dioxide
F	F-Series	NUG	Non-Utility Generation	M	Millions		
G	G-Series			MW	Megawatts		

FIGURE T8-7. Supply Option Comparison (Base Category / Gas Only)

Option	Fuel Type	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020		
									SO_2 (Tons)	NO_x (Tons)	CO_2 (KTons)
Landfill Methane (1x2 MW)	Methane	88087	52.0	-294	44.7	50.2	30846	33787	518472	437164	127369
CHAT, F-CT (1x288 MW)	Natural Gas	88158	52.1	-377	44.8	50.3	30508	33287	538942	442617	138931
CC (1x470 MW)	Natural Gas	88204	52.1	-429	44.8	50.4	30599	33492	538341	442587	138870
CC Repowering, Generic (1x425 MW)	Natural Gas	88213	52.1	-440	44.8	50.4	30776	33561	531387	440361	138712
Supercritical PC Plant (4x300 MW)	**Coal**	**88266**	**52.2**	**-524**	**44.9**	**50.4**	**30942**	**33845**	**524181**	**437457**	**138943**
Repower ALF w/ CC (1x705 MW)	Natural Gas	88301	52	-507	45	50	30725	33610	531197	428773	138666
NUG - Generic IPP CC (1x150 MW)	Natural Gas	88326	52.1	-511	44.7	50.4	30182	33212	538736	442762	138787
NUG - Generic IPP CC (2x260 MW)	Natural Gas	88330	52.2	-542	44.7	50.5	30182	33212	521829	437156	137280
Small CC (1x42 MW)	Natural Gas	88339	52.2	-563	44.8	50.5	30661	33586	538189	442805	138783
Repower JOF 7-10 w/ CC (1x465 MW)	Natural Gas	88344	52.2	-608	45.0	50.5	31331	34082	514674	434521	138661
Power Purchase - Base Load (1x300 MW)	Natural Gas	88449	52.2	-633	44.7	50.5	30182	33212	537802	442431	138720
Fuel Cell - MCFC or SOFC (1x2 MW)	Natural Gas	88684	52.3	-785	44.7	50.6	30867	34064	537059	442471	138373
Small Cogeneration CC (3x10 MW)	Natural Gas	89293	52.7	-1387	44.7	51.1	30485	33491	519502	438804	137040
Generic CC Cogeneration (2x210 MW)	Natural Gas	89580	52.8	-1587	44.6	51.2	29880	32901	518960	436333	136234

Acronym Key:

ALF	Allen Fossil Plant	MCFC	Molten Carbonate Fuel Cell	K	Thousands	RIM	Rate Impact Measure
CC	Natural Gas Combined Cycle	NUG	Non-Utility Generation	M	Millions	SO_2	Sulfur Dioxide
CHAT	Cascaded Humidified Advanced Turbine	PC	Pulverized Coal	MW	Megawatts		
IPP	Independent Power Producer	SOFC	Solid Oxide Fuel Cell	MWh	Megawatt-Hours		
JOF	Johnsonville Fossil Plant	CO_2	Carbon Dioxide	NO_X	Nitrogen Oxides		

FIGURE T8-8. Supply Option Comparison (Base Category / Nuclear Only)

Option	Fuel Type	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020 SO_2 (Tons)	NO_x (Tons)	CO_2 (KTons)
BLN - Partnership	Nuclear	88135	52.1	-382	44.7	50.4	30220	33050	522617	436943	136391
ALWR (1x1300 MW)	Nuclear	88258	52.2	-533	45.0	50.4	31222	33997	518890	435684	135874
Supercritical PC Plant (4x300 MW)	**Coal**	**88266**	**52.2**	**-524**	**44.9**	**50.4**	**30942**	**33845**	**524181**	**437457**	**138943**
Gas Turbine - Modular Helium Reactor (3x289 MW)	Nuclear	88348	52.2	-636	45.1	50.5	31362	34241	519552	435951	135939
BFN 1 Recovery w/ Fixed Cost (1x1065 MW)	Nuclear	88380	52.2	-622	45.0	50.4	30996	33868	523209	437234	136495
Recover BFN 1 (1X1065 MW)	Nuclear	88599	52.4	-863	45.1	50.6	31390	34111	522685	437121	136299
BLN 1&2 Cancellation	Nuclear	88266	52.2	-524	44.9	50.4	30942	33845	524181	437457	138943
BFN 1 Cancellation	Nuclear	88266	52.2	-524	44.9	50.4	30942	33845	524181	437457	138943
WBN 2 Cancellation	Nuclear	88266	52.2	-524	44.9	50.4	30942	33845	524181	437457	138943
Completion of BLN 2 (1x1212 MW)	Nuclear	88338	52.2	-560	44.9	50.3	31064	33886	523272	437236	136542
Completion of WBN 2 (1x1170 MW)	Nuclear	88533	52.3	-773	45.0	50.6	31232	34134	522943	437178	136357
Completion of BLN 1 (1x1212 MW)	Nuclear	88685	52.4	-896	45.1	50.4	31347	34000	523944	437570	136205

Acronym Key:

ALWR	Advanced Light Water Reactor	WBN 2	Watts Bar Nuclear Plant Unit 2	M	Millions	NO_X	Nitrogen Oxides
BFN 1	Browns Ferry Nuclear Plant Unit 1	CO_2	Carbon Dioxide	MW	Megawatts	RIM	Rate Impact Measure
BLN 1&2	Bellefonte Nuclear Plant Units 1&2	K	Thousands	MWh	Megawatt-Hours	SO_2	Sulfur Dioxide

FIGURE T8-9. Supply Option Comparison (Base Category / Renewables Only)

Option	Fuel Type	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020 SO_2 (Tons)	NO_x (Tons)	CO_2 (KTons)
RDF Companion Boiler - WBF (1x60 MW)	RDF	87268	51.6	350	45.0	49.7	31840	34488	521935	438327	136912
RDF Companion Boiler - Kingston (1x60 MW)	RDF	87268	51.6	350	45.0	49.7	31840	34488	521935	438327	136912
RDF - FBC Repower - WBF (1x56 MW)	RDF	87426	51.7	256	45.1	49.7	31956	34799	521528	438149	136835
RDF-Fired Stoker (1x40 MW)	RDF	87514	51.8	29	45.5	49.9	33601	36182	520247	437069	136718
Wind - 39M Variable Speed A Turbine (444x.45 MW)	Renewable	88265.7	52.2	-537	44.9	50.5	31131	34011	522088	436579	138356
Supercritical PC Plant (4x300 MW)	**Coal**	**88266.5**	**52.2**	**-524**	**44.9**	**50.4**	**30942**	**33845**	**524181**	**437457**	**138943**
Wind - 33M Variable Speed A Turbine (285x.35 MW)	Renewable	88303	52.2	-575	44.9	50.5	31159	34031	521858	436496	138318
Biomass WTE Boiler (1x100 MW)	SRWC	88619	52.4	-855	44.9	50.7	30990	33884	537493	442477	137295
Large Solar-Photo - Fixed Flat Plate (1x50 MW)	Solar	88820	52.5	-1105	44.9	51.0	31558	34415	533805	440998	137525

Acronym Key:

A	Advanced	M	Meter	WBF	Watts Bar Fossil Plant	M	Millions	RIM	Rate Impact Measure
FBC	Fluidized Bed Combustion	PC	Pulverized Coal	WTE	Whole Tree Energy	MW	Megawatts	SO_2	Sulfur Dioxide
		Photo	Photovoltaic	CO_2	Carbon Dioxide	MWh	Megawatt-Hours		
		RDF	Refuse-Derived Fuel	K	Thousands	NO_X	Nitrogen Oxides		

FIGURE T8-10. Supply Option Comparison (Base Category / Hydro Only)

Option	Fuel Type	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020 SO_2 (Tons)	NO_x (Tons)	CO_2 (KTons)
NUG - Generic IPP Run of River Hydro (4x20 MW)	Renewable	88134	52.0	-343	44.7	50.3	30220	33098	536938	441964	138416
Hydro Modernization	Renewable	88394	52.2	-641	44.9	50.5	30902	33799	530570	439794	138793
Hydro - Existing Nonpower Projects (1x10 MW)	Renewable	88522	52.3	-805	45.0	50.7	31542	34275	520160	436025	138243
Hydro - Existing Projects (1x24 MW)	Renewable	88777	52.5	-1077	45.1	50.9	31783	34670	521280	436443	137992
Hydro - New Conventional Projects (1x65 MW)	Renewable	89431	52.9	-1805	45.4	51.6	32985	35382	518447	435504	137341

Acronym Key:

IPP Independent Power Producer
NUG Non-Utility Generation
CO_2 Carbon Dioxide
K Thousands
M Millions
MW Megawatts
MWh Megawatt-Hours
NO_X Nitrogen Oxides
RIM Rate Impact Measure
SO_2 Sulfur Dioxide

FIGURE T8-11. Supply Option Comparison (Peak Category / Gas Only)

Option	Fuel Type	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020 SO_2 (Tons)	NO_x (Tons)	CO_2 (KTons)
CHAT, G-CT (1x400 MW)	Natural Gas	88141	52.1	-362	44.7	50.3	30494	33322	538715	442532	138919
Water Spray Cooling CT Inlet Air	Natural Gas	88220	52.1	-474	44.9	50.4	30847	33721	524476	437570	139003
Intercooled Aeroderivative CT (1x125 MW)	Natural Gas	88256	52.2	-519	44.9	50.4	30975	33871	524211	437446	138914
Simple Cycle CT (1x150 MW)	Natural Gas	88266	52.2	-524	44.9	50.4	30942	33845	524181	437457	138943
Power Purchase - Peaking (1x300 MW)	Natural Gas	88277	52.2	-526	44.9	50.4	30838	33765	524166	437454	138947
New CT for Steam to DuPont (Johnsonville) (1x174 MW	Natural Gas	88337	52.2	-606	44.9	50.5	31107	33973	523683	437296	138886
Integrated Fuel Cell CT (1x2.5 MW)	Natural Gas	88502	52.3	-726	44.9	50.6	31231	34205	523572	437163	138661

Acronym Key:

CHAT Cascaded Humidified Advanced Turbine
CT Combustion Turbine
G G-Series
CO_2 Carbon Dioxide
K Thousands
M Millions
MW Megawatts
MWh Megawatt-Hours
NO_X Nitrogen Oxides
RIM Rate Impact Measure
SO_2 Sulfur Dioxide

FIGURE T8-12. Supply Option Comparison (Storage Options Comparison)

Option	Fuel Type	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020		
									SO_2 (Tons)	NO_X (Tons)	CO_2 (KTons)
Raccoon Mountain Modernization	Electricity	87891	51.9	-165	44.9	50.1	30994	33823	514655	434026	137708
Raccoon Mountain Addition	Electricity	88030	52.0	-328	45.0	50.3	31169	33922	514987	434183	137615
Advanced Battery (1x20 MW)	Coal	88050	52.0	-333	44.9	50.3	31023	33812	514347	433925	137542
SMES (1x500 MW)	Coal	88052	52.0	-341	44.9	50.3	31092	33882	514415	433964	137567
CAES w/ Recuperation (3x337 MW)	Natural Gas	88197	52.1	-466	44.9	50.4	30956	33753	523053	436994	138930
Inlet Air Precooling w/Storage (16x61 MW)	Natural Gas	88200	52.1	-457	44.9	50.4	30891	33615	524312	437574	138988
CAES w/ Humidification (3x337 MW)	Natural Gas	88206	52.1	-471	44.9	50.4	30943	33699	523890	437252	139007
IGCASH plus NGCASH (1x850 MW)	Natural Gas	88268	52.2	-532	44.9	50.4	31087	33982	518388	435435	138397
Lead Acid Battery (1x20 MW)	Electricity	88292	52.2	-554	44.9	50.5	31011	33901	524370	437513	138933
Rorex Creek Pump-Storage (3x292 MW)	Electricity	88316	52.2	-604	45.0	50.5	31135	33989	525653	437945	139052
Laurel Branch Pump-Storage (4x386 MW)	Electricity	88323	52.2	-611	45.0	50.5	31147	33999	525611	437932	139046
Reynolds Creek Pump-Storage (3x366 MW)	Electricity	88384	52.2	-680	45.0	50.6	31252	34078	525172	437783	138983
IGCASH (1x410 MW)	Coal / Gas	88401	52.2	-676	45.0	50.5	31251	34109	517682	435197	138814
NUG - Generic IPP Pump-Storage	Electricity	88569	52.3	-786	44.9	50.6	30838	33711	523328	437020	138497

Acronym Key:

CAES	Compressed Air Energy Storage	NUG	Non-Utility Generation	MW	Megawatts
IGCASH	Integrated Gasification Compressed Air Storage with Humidification	SMES	Superconducting Magnetic Energy Storage	MWh	Megawatt-Hours
		CO_2	Carbon Dioxide	NO_X	Nitrogen Oxides
IPP	Independent Power Producer	K	Thousands	RIM	Rate Impact Measure
NGCASH	Natural Gas Compressed Air Storage with Humidification	M	Millions	SO_2	Sulfur Dioxide

FIGURE T8-13. Customer Service Options (Beneficial Electrification)

Option	System Peak MW Impact	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020		
									SO_2 (Tons)	NO_X (Tons)	CO_2 (KTons)
Supercritical PC Plant (4 X 300 MW)		**88266**	**52.2**	**-524**	**44.9**	**50.4**	**30942**	**33845**	**524181**	**437457**	**138943**
Residential HVAC and Water Heating	110	88780	51.9	2571	44.8	50.3	30600	33524	535702	441408	139580
Process Melting	-71	88817	51.8	-450	44.9	50.4	31336	34043	526744	438231	140179
Cooking and Security Lighting	-22	88822	52.0	3179	44.9	50.5	31304	34209	523538	437094	139696
Process Heating and Melting	-78	88872	51.8	-457	44.9	50.5	31343	34048	526517	438161	140155
Electrotechnologies/ Textiles	-2	89060	51.9	-145	45.0	50.5	31353	34189	525578	437855	140090
Security Lighting and Lawn Mowers	0	89124	51.9	-494	44.9	50.4	30983	33800	529809	439384	139651
Electrotechnologies/ Food Processing	-47	89139	51.8	-457	44.9	50.4	31337	34043	526741	438230	140179
Electrotechnologies/ Chemicals & Metals	-5	89239	51.8	-458	44.9	50.5	31348	34184	526016	437996	140141
Curing & Drying	-16	89511	51.8	-241	44.9	50.5	31347	34052	526334	438102	140130
Environmental Technologies	-29	89802	51.8	-475	44.9	50.5	31345	34049	526461	438147	140149
Fleet Vehicles	0	89933	52.0	-140	45.0	50.6	31016	33782	530207	439499	139572
Space Conditioning and Water Heating	-19	91311	51.5	14265	45.2	50.7	31258	34174	534849	440960	141249
Electric Buses	0	92036	52.0	2685	44.9	50.4	30979	33795	529656	439336	139644
Electric Autos	0	93145	52.0	6689	44.9	50.5	31010	33776	530307	439532	139593

Acronym Key:

CT	Combustion Turbine	MW	Megawatts
CO_2	Carbon Dioxide	MWh	Megawatt-Hours
HVAC	Heating, Ventilation, Air Conditioning	NO_X	Nitrogen Oxides
K	Thousands	RIM	Rate Impact Measure
M	Millions	SO_2	Sulfur Dioxide

FIGURE T8-14. Customer Service Options (Commercial Sector)

Option	System Peak MW Impact	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020		
									SO_2 (Tons)	NO_X (Tons)	CO_2 (KTons)
Energy Efficient Rates	53	87935	52.7	-1040	45.0	50.6	30600	33508	521306	436510	137385
Water Heating Conversion	27	87950	52.4	-645	44.8	50.4	30590	33597	527044	438430	138233
Commercial Lighting Rebates	417	87980	52.5	-698	44.9	50.5	30593	33502	524854	437685	137798
Comprehensive Measure Financing	105	88029	52.4	-638	44.8	50.4	30591	33280	527894	438762	138033
Comprehensive Appliance Rebates	57	88074	52.5	-648	44.9	50.5	30597	33506	525191	437797	137853
Comprehensive Measure Rebates	190	88109	52.4	-569	44.9	50.5	30596	33138	527913	438783	137993
Commercial New Construction	124	88130	52.5	-672	44.9	50.5	30598	33286	527515	438670	138016
Small Commercial Retrofit-Direct Install	122	88147	52.5	-695	45.0	50.5	30660	33707	525374	437805	138003
Commercial New Construction-Renewables	23	88183	52.4	-563	44.8	50.4	30595	33283	527671	438685	138000
Commercial Cool Storage	57	88238	52.1	-883	44.8	50.4	30596	33155	534000	440930	139002
Commercial HVAC Rebates	133	88256	52.4	-608	44.9	50.5	30566	33322	529300	439282	138227
Supercritical PC Plant (4 X 300 MW)		**88266**	**52.2**	**-524**	**44.9**	**50.4**	**30942**	**33845**	**524181**	**437457**	**138943**
Rooftop Cool Storage	70	88275	52.1	-474	44.8	50.3	30597	33156	533986	440920	138997
Small Commercial HVAC Maintenance Program	14	88395	52.3	314	44.8	50.3	30590	33002	529664	439388	138204

Acronym Key:

CT Combustion Turbine
HVAC Heating, Ventilation, Air Conditioning
CO_2 Carbon Dioxide
K Thousands
M Millions
MW Megawatts
MWh Megawatt-Hours
NO_X Nitrogen Oxides
RIM Rate Impact Measure
SO_2 Sulfur Dioxide

FIGURE T8-15. Customer Service Options (Industrial Sector)

Option	System Peak MW Impact	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020		
									SO_2 (Tons)	NO_X (Tons)	CO_2 (KTons)
Industrial Tech Rebates - HE Motors	11	87819	52.6	-803	44.9	50.5	30594	33361	523008	437050	137429
Industrial Tech Rebates - AS Drives	4	87969	52.7	-967	45.0	50.6	30569	33179	522697	436968	137169
Industrial Process EE - Distributor Served	110	88037	52.7	-774	44.9	50.5	30561	33171	523051	437055	137186
Industrial Process EE - Direct Served	98	88049	52.7	-776	44.9	50.5	30562	33171	523011	437043	137180
Supercritical PC Plant (4 X 300 MW)		**88266**	**52.2**	**-524**	**44.9**	**50.4**	**30942**	**33845**	**524181**	**437457**	**138943**
Industrial Tech Rebates - CA Efficiency	3	88356	52.7	-893	45.1	50.7	30515	33443	522273	436820	137311

Acronym Key:

AS Adjustable Speed
CA Compressed Air
CT Combustion Turbine
EE Energy Efficiency
HE High Efficiency
Tech Technology
CO_2 Carbon Dioxide
K Thousands
M Millions
MW Megawatts
MWh Megawatt-Hours
NO_X Nitrogen Oxides
RIM Rate Impact Measure
SO_2 Sulfur Dioxide

FIGURE T8-16. Customer Service Options (Residential Sector)

Option	System Peak MW Impact	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020		
									SO_2 (Tons)	NO_X (Tons)	CO_2 (KTons)
Res Water Heater Conversion Program	89	87725	52.8	-610	44.9	50.6	30594	33556	519719	435940	137147
Res Refrigerator Turn-in	18	87834	52.9	-828	45.2	50.6	30516	33773	521465	436542	137386
Res Heat Pump Water Heater Leasing	88	87855	52.8	-2661	44.9	50.6	30556	33313	520491	436216	136960
Res Efficiency Products Catalog	99	87864	52.6	-582	44.9	50.5	30590	33596	523229	437142	137720
Res New Homes	121	87889	52.6	-649	44.9	50.5	30594	33283	524254	437503	137494
Res Lighting Retail Component	75	87892	52.5	-659	44.8	50.5	30592	33359	524547	437571	137621
Res Heat Pump Leasing	334	87931	52.3	-735	44.8	50.4	30590	33358	528759	439077	138249
Res Low Income	66	87935	52.6	-593	45.0	50.6	30596	33505	523160	437136	137608
Res Direct Install	386	87937	52.6	-585	45.0	50.6	30595	33649	522999	437069	137746
Res Heat Pump Rebates	305	87969	52.4	-415	44.8	50.4	30592	33134	528956	439143	138159
Res Self-Audit	22	87995	52.5	-988	44.9	50.5	30593	33646	523753	437296	137905
Res Student Self-Audit	22	88042	52.6	-1010	44.9	50.5	30606	33515	524314	437524	137691
Res Ground Source Heat Pump Leasing	19	88061	52.3	-1934	44.8	50.3	30558	32618	531340	440046	137928
Res Heat Pump Loans	317	88079	52.3	-477	44.8	50.4	30592	33229	529434	439304	138353
Res Efficient Air Conditioning	85	88131	52.2	-436	44.8	50.4	30595	33283	530994	439848	138588
Res Appliance Rebates	26	88230	52.9	-999	45.2	50.9	30560	33338	522149	436717	136873
Supercritical PC Plant (4 X 300 MW)		**88266**	**52.2**	**-524**	**44.9**	**50.4**	**30942**	**33845**	**524181**	**437457**	**138943**

Acronym Key:

CT	Combustion Turbine	K	Thousands	MWh	Megawatt-Hours	SO_2	Sulfur Dioxide
Res	Residential	M	Millions	NO_X	Nitrogen Oxides		
CO_2	Carbon Dioxide	MW	Megawatts	RIM	Rate Impact Measure		

FIGURE T8-17. Customer Service Options (Load Management Programs)

Option	System Peak MW Impact	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020		
									SO_2 (Tons)	NO_X (Tons)	CO_2 (KTons)
Commercial Group Load Curtailment	173	88096	52.2	-446	44.8	50.4	30589	33226	532452	440356	138799
Res Load Management - Air Conditioners	54	88179	52.2	-539	44.8	50.4	30591	33645	530137	439487	138812
Supercritical PC Plant (4 X 300 MW)		**88266**	**52.2**	**-524**	**44.9**	**50.4**	**30942**	**33845**	**524181**	**437457**	**138943**
Res Load Management w/ SCADA	32	88294	52.2	-681	44.9	50.6	30746	34077	527879	438532	138745
Res Load Management - Water Heaters	86	88328	52.2	-674	44.9	50.5	30592	33555	530515	439642	138780
Flexible Load Managed Water Heater Program	86	88378	52.2	-656	44.9	50.5	30622	33581	531283	439866	138780
Res Load Management - Storage Water Heaters	41	88463	52.3	-791	45.0	50.6	30631	33590	530444	439604	138687
Res Load Management - New Technology	64	88474	52.3	-806	45.2	50.5	30840	34169	527053	438305	138691

Acronym Key:

CT	Combustion Turbine	CO_2	Carbon Dioxide	MWh	Megawatt-Hours
Res	Residential	K	Thousands	NO_X	Nitrogen Oxides
SCADA	Supervisory Control and Data Acquisition Systems	M	Millions	RIM	Rate Impact Measure
		MW	Megawatts	SO_2	Sulfur Dioxide

FIGURE T8-18. Customer Service Options (Miscellaneous Programs)

Option	System Peak MW Impact	Total Resource Costs (95 M $)	RIM Test ($/MWh)	Customer Value Test (95 M $)	Short-Term Rates ($/MWh)	Mid-Term Rates ($/MWh)	Debt 2001 (M $)	Debt 2007 (M $)	Emissions Average Annual 1996-2020		
									SO_2 (Tons)	NO_X (Tons)	CO_2 (KTons)
Landfill Gas/ Fuel Cells	43	87544	52.6	-594	44.8	50.4	30553	33310	522179	436724	137086
Small Head Hydro	5	87717	52.7	-428	44.9	50.5	30591	33554	521513	436547	137435
Existing Cogeneration - Commercial	75	87842	52.5	-557	44.8	50.4	30588	33642	524667	437629	137965
Commercial Flexible Lighting Options	570	87963	52.5	-603	44.9	50.5	30592	33462	524997	437715	137862
New Cogeneration - Industrial	30	88031	52.6	-622	44.9	50.5	30588	33642	521910	436688	137596
Flexible Comprehensive Financing	224	88044	52.4	-536	44.8	50.4	30591	33279	527532	438632	137963
Flexible Group Load Curtailment	275	88161	52.2	-507	44.8	50.4	30589	33643	529877	439360	138792
New Cogeneration - Commercial	17	88193	52.4	-541	44.8	50.4	30589	33643	525770	438011	138129
Supercritical PC Plant (4 X 300 MW)		**88266**	**52.2**	**-524**	**44.9**	**50.4**	**30942**	**33845**	**524181**	**437457**	**138943**
Photovoltaics/ Technology Advancement	2	88610	52.3	378	44.8	50.4	30594	33152	530673	439760	138431
Photovoltaics	1	89099	52.3	1631	44.9	50.4	30603	33292	529929	439503	138375

Acronym Key:

CT	Combustion Turbine	M	Millions	NO_X	Nitrogen Oxides
CO_2	Carbon Dioxide	MW	Megawatts	RIM	Rate Impact Measure
K	Thousands	MWh	Megawatt-Hours	SO_2	Sulfur Dioxide

UNCERTAINTY IN THE RESOURCE PLAN

Summary

Energy resource plans being made today must account for the undeniable fact that the future will be unlike expectations of the future. If TVA knew the future state of the energy world, resource plans could be made simply to best meet various planning criteria. However, the future is uncertain. Resource plans must account for a range of possible future events. Plans must be flexible enough to change as certain key parameters change; also, they should be able to withstand shifts in the long-term parameters that drive electric utility operation.

UNCERTAINTY TREATMENT PROCESS

An exhaustive list of parameters that could vary in the future was identified through discussions in the Energy Vision 2020 Building Block teams, the Energy Vision 2020 Review Group, the Forecast Review Board, the Tennessee Valley Industrial Committee, Tennessee Valley Public Power Association, and environmental review groups; as well as reviews of other utility resource plans. Almost 50 individual items were identified as uncertain items to be explored in Energy Vision 2020.

Each uncertain item is described and a range of possible outcomes identified for the future. Since in Energy Vision 2020, TVA is evaluating its resource options for a number of planning criteria, variations in the item are needed for the different criteria. Four planning criteria are being used to represent the more extensive list. These are total resource costs, electric rates, carbon dioxide output, and debt.

RESULTS OF THE UNCERTAINTY REVIEW PROCESS

The evaluation of each uncertain item for the four planning criteria shows items that are most critical in future resource planning. They result in the largest variation from the mid-range forecast and thus should be considered further in the next, more detailed phase of the evaluation.

Issues that were found to be most sensitive include the following;

- Load Growth
- Nuclear Issues
  - Capacity Factor
  - Operations and Maintenance Cost
  - Capital Cost
- Environmental Issues
  - Carbon Dioxide Compliance
  - Air and Water Environmental Controls
- Price
  - Natural Gas
  - Revenue from Coproducts (Combined Cycle)

Issues for which selected sensitivity evaluation can be performed include the nuclear moratorium and the inability to site central station generating capacity.

Process to Represent Uncertainty in the Resource Plan

As stated previously, if TVA knew the future state of the energy world, resource plans could be made simply. Alternative actions would be chosen to meet the various planning criteria without risk.

The real world is, however, highly uncertain. When energy resource plans were being made for 1995 twenty years ago, innumerable factors about the energy world in 1995 were not known. Load growth was projected to double every seven years. Construction costs were projected to be stable with project construction lead times short; fuel prices were to remain relatively low. Of course, these projections were far from the actual experience. Neither the Public Utility Regulatory Policy Act, the National Energy Act of 1992, nor the pile of regulations brought on by such events as Three Mile Island existed. There were no regulations on sulfur dioxide emissions and other environmental issues. Forecasting twenty years into the future still remains highly speculative, yet planning resource capabilities requires a long-term outlook.

Resource plans must account for a range of possible future events. Plans should be sufficiently flexible to change as key parameters change, and they should, once implemented, be capable of withstanding shifts in the long-term parameters that drive electric utility operation (robustness).

FIGURE T8-19.
Normal Distribution

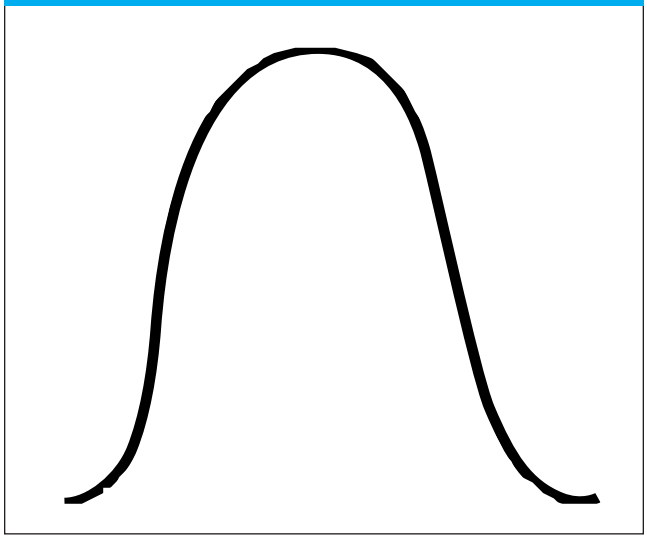
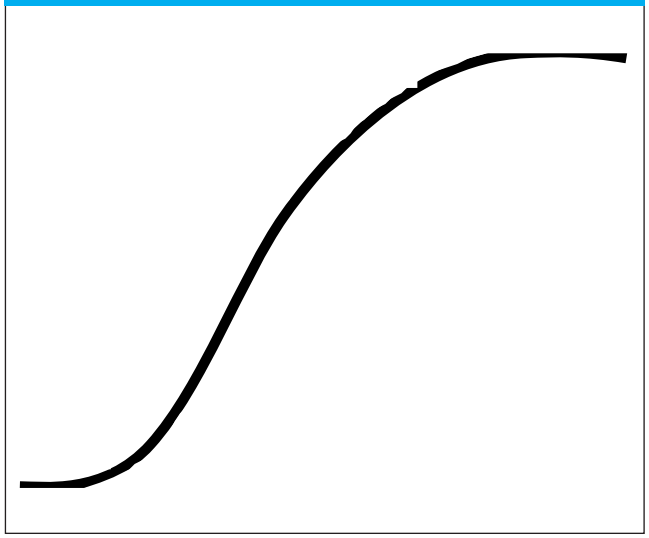


FIGURE T8-20.
Cumulative Distribution



Two important questions are: "What future events should be considered when making resource plans?" and "What future events, if known today, would change the plan significantly?" In the planning process, it is desirable to ensure that all parameters that can impact resource plan selection are sufficiently represented and considered.

Identification of numerous parameters that could vary in the future is the first step in the representation of uncertainty. An exhaustive list of parameters has been developed through discussions by the Energy Vision 2020 Building Block teams, the Forecast Review Board, and Energy Vision 2020 Review Group and in analyzing resource plans from many other utilities.

Each issue or parameter must be quantified so that its impact on resource plans can be evaluated. A wide range of future possibilities of the parameter was developed that typically is represented by a probability distribution as described in the following section.

An exhaustive resource evaluation would include every parameter that has been identified as an issue. This list of anywhere from 20 to 100 issues would be explored fully and all evaluations would consider their impacts.

Realistically and computationally, the number of parameters must be reduced to those that are significant to the decision at hand. In order to determine those uncertain parameters that can significantly impact a resource planning decision or actually change a decision, a sensitivity evaluation is performed on each parameter.

These sensitivity diagrams, sometimes referred to as "tornado" diagrams because of their shape, help to narrow the large number of uncertain issues to a much smaller, more manageable list.

Issues that can cause significant impacts on resource plan results are then used in the complete, detailed evaluation and integration of supply- and demand-side alternatives.

A Quantifiable Description of the Future

Given that the future is so uncertain, how can it be considered? In general, parameters can be described mathematically by a probability distribution. A probability distribution describes the likelihood of the value of a parameter. Typically, a "normal" distribution can be used to describe most uncertain parameters. *Figure T8-19* shows a normal distribution where the y-axis indicates the probability of the value that occurs on the x-axis.

A cumulative distribution can then be constructed that accumulates the probabilities and the values sum so that *Figure T8-19* becomes as shown in Figure *T8-20*. The y-axis accumulates to 1.0 (or 100 percent). The accumulated level represents that percentage of the values that are at least that large.

In order to utilize this information in a resource plan, it is necessary to determine discrete values that can be used to represent the distribution. Typically, 3 points on the cumulative probability distribution are chosen to represent the curve so that the points represent a value that has a 10 percent prob-

FIGURE T8-21. **Uncertainty Items from Sample IRPs**

Bonneville Power Administration
- Load Growth
- Salmon Migration
- System Operation
- Endangered Species Act
- Availability of Reserves
- Capacity from Neighbors (Contracted)
- Extreme Weather Impacts

Duke Power Company
- Load Growth
- Load Factor
- Coal Fuel Price Escalation
- Oil Fuel Price Escalation
- Capital Cost (Coal, Combustion Turbine, Combined Cycle)

Entergy
- Weather
- Mechanical Failures
- Customer Demand
- Inflation
- Fuel Prices (Gas & Oil)

Georgia Power Company
- Financial
- Environmental Cost
- Load Growth
- Fuel Cost
- Unit Cost

New England Electric System
- Load Growth
- Schedule Delays
- Conservation/Load Management Effectiveness
- Performance of Existing Facilities
- Schedule Delays of Cogeneration Sources
- Future Gas & Coal Prices
- Non-Utility Generator Siting/Licensing Problems
- Externalities

Niagara Mohawk Company
- Load Growth
- Economic Growth
- Fossil Fuel Prices
- Regulation
- Externalities
- Non-Utility Generators (NUGS)
- Demand-Side Management (DSM) Participation

Pacific Corporation
- Load Growth
- Electrification
- Loss of Resources
- High Gas Prices
- Carbon Dioxide Tax
- Environmental Externalities
- Renewable Resources
- Demand-Side Acquisition
- Plant Performance

Virginia Electric Power Company
- Economic Growth
- Load Growth
- Fossil Fuel Prices
- Regulation
- Price of Sulfur Allowance
- Demand-Side Effectiveness
- Plant Efficiency and Reliability

Wisconsin Power and Light Company
- Economy
- Fuel Price
- Fuel Availability
- Technologies

Uncertain parameters considered as issues by other electric utilities throughout the country are shown in this table.

ability of being that amount or less; a 50 percent probability of being that amount or less; and a 90 percent probability of being that amount or less.

These three points represent, respectively, approximately 25, 50, and 25 percent of the distribution.

There are numerous techniques available for developing these cumulative probability distributions. Such techniques include probability assessment interviews with experts, delphi techniques, and historical data.

Typical Uncertain Parameters in Integrated Resource Planning

Figure T8-21 shows parameters considered in sample integrated resource plans from electric utilities in the country over the past five years. Some issues, such as load growth and fuel cost, are fairly standard. Other issues may be regional, such as "Salmon Migration" an issue important in the Pacific Northwest. In this part of the country, it may be air quality in the Smoky Mountain National Park or mining restrictions for Appalachian coal.

FIGURE T8-22. **Example of Future Drivers in Utility Industry and How They Translate into Resource Planning Parameters**

DRIVERS (SAMPLES)	TRANSLATE INTO THIS UNCERTAIN PARAMETER
Environment	
• Continuing Increase in Controls	Cost of Existing Coal Availability of Existing Coal
• Local Requirements	Cost/Availability of Coal
Fuel Markets	
• Low-Cost Alternate Fuels	Low Fuel Price
• High Availability of Renewables	Low-Cost Renewable
• Reduced Availability of Gas/Oil	Gas Price
• Abundance of Gas/Oil	Gas Price
• Foreign Markets Develop for U.S. Coal	High Coal Price
Nuclear Industry	
• Public Acceptance, Good Performance, Relicense	Unit Availability Capacity Factor
• Increase Regulatory Requirements	Capacity Factor Schedule Delays Cost
• Moratorium on Nuclear Power	Unit Availability
Regulation	
• Fence Stays/Lose Anti-Cherry Picking	Lose Load
• Wholesale Deregulation	Gain/Lose Load
• Retail Deregulation	Gain/Lose Load
Technology	
• Breakthrough on: Fuel Cells, Combined Cycle, Fusion, Material	Capital Cost Operating Cost
• Transmission Breakthrough	Loss Reduction
• Telecommuting/Interactive Customers	Reduced Load
• Beneficial Electrification	Increased Load
• Cheap Natural Gas End Use	Reduced Load
Economic Activity	
• Cost Containment - Decentralize Work Force	Load Increase
• International Competition: Exports - Technology and Service	Load Increase
• International Competition: Imports Due to U.S. Regulation, High Wages, Declining Material Resources	Load Decrease
• Graying of Valley	Load Increase
Legislation	
• Reduce TVA Debt Ceiling to $15 Billion	Increased Rates
• TVA Chosen as Federal Showplace for Energy and Environment	Increased Load

Issues raised by various groups have been translated into quantifiable values for the resource evaluation.

Specific Uncertainty Building Block Results

The Energy Vision 2020 Uncertainty Building Block Team developed an exhaustive list of issues from previous meetings, other building blocks, and integrated resource plans. Each of these items has been described in this document and a range of outcomes developed. A set of key uncertainties is identified later in this document.

Figure T8-22 shows how the issues raised by various groups have been translated into quantifiable values for the resource evaluation. In the environmental area, for example, the continuing increase in controls on particular environmental emissions can translate into reduced availability of the generating plants, higher capital cost to continue to operate the plants, and increased operation and maintenance costs to operate the plants.

Exhaustive List of Uncertainties for Energy Vision 2020

Figure T8-23 shows the complete list of uncertain parameters that have been considered in Energy Vision 2020. These items are described briefly in the following section.

ISSUE 1: HYDROELECTRIC ENERGY

Energy supplied by the TVA-operated hydroelectric plants varies depending on weather and associated rainfall patterns in the Valley.

Historical TVA weather and rainfall data for almost 100 years has been modeled with the current TVA hydro system in place. While there are some hydro modernization projects underway, expected hydroelectric generating output is not expected to vary greatly because of it. The range of

FIGURE T8-23. **Uncertainties in Resource Plan**

ITEM	(UNITS)	RANGE Low	Medium	High
HYDRO ENERGY	(Billion kWh)	13	18 [1]	22
COAL				
Capital Additions & Improvements	($/kW/Year) (94$)	12.5	13.6 [1]	14.8
Operating & Maintenance Cost	($/kW/Year) (94$) (Escalation)	21.7 -2% Base	21.7 [1] -1% Base	21.7 +1% Base
Plant Life Extension	(MW)	No Retirements	No Retirements	750 MW Retired
Reliability of New Units	(Equivalent Forced Outage Rate)	6%	9% [1]	20%
Fuel Cost (5# Coal in 2000)	(¢/MBtu) (Escalation Rate)	100 2.8%	109 [1] 3.3%	121 4.0%
Fuel Cost Existing System	(¢/MBtu) (Escalation Rate)	119 3.0%	131 3.5%	146 4.1%
COMBINED CYCLE				
Market Price of Coproduct in 2000 for Integrated Gasification Combined Cycle	($/Ton)	91	262 [1]	320
Gas Cost (2000)	(¢/MBtu) (Escalation Rate)	256 2.4%	342 [1] 5.3%	418 7.9%
NUCLEAR				
Moratorium		Normal Operation	Normal Operation [1]	Units Do Not Operate after 2006
Return to Service/Commercial Operation Date		Base Schedule [1]	12-17 Month Delay	24-33 Month Delay
Capacity Factor	(%)	55	67 [1]	86
Operating Cost	($/kW/Year) (94$)	55	69 [1]	83
Fuel Cost	(¢/MBtu)	35	41 [1]	50
Spent Fuel Storage	($/MWh)	1.0	1.0 [1]	2.0
Capital - Additions & Improvements	($/kW/Year)	9	12 [1]	19
Capital Cost	(Billion $)			
	Bellefonte 1	1.3	2.6 [1]	3.5
	Bellefonte 2	0.9	1.8	2.4
	Watts Bar 2	1.2	2.4	3.2
	Browns Ferry 1	1.1	2.2	2.9
Browns Ferry License Extension		No Extension, Replace in 2013	Yes [1]	Yes
Summer Limits on Discharge Water Temperature		Lose 150 MW	No Impacts [1]	No Impacts
Decommissioning Cost	(Million $/Unit)	200	300 [1]	600
COGENERATION				
Cost	($/kW)	159	175 [1]	263
Availability	(MW)	1800	2000 [1]	N/A
TRANSMISSION				
Electromagnetic Field		No Additional Impacts [1]	+ $50 Million/Unit for New Site Central Generation	+ 50% Cost of Overall Trans-mission System
Transmission Limit Wheeling Requirements		Increased Reserve Margin for 1200 MW of Reduced TM Capability	Normal TM Capability [1]	Normal TM Capability

FIGURE T8-23. **Uncertainties in Resource Plan** *CONTINUED*

ITEM	(UNITS)	RANGE Low	Medium	High
PURCHASED POWER				
Quantity		1125 MW	1500 MW [1]	1875 MW
Price (2000)	(Escalation)	-2% Medium	56 $/MWh (6.5% Escalation)	+3% Medium
ENVIRONMENTAL QUALITY				
Carbon Dioxide Emission Cost		Voluntary Compliance No Additional Controls [1]	$5/Ton by 2002 above Limits	$5/Ton by 2002 and $10/Ton by 2010 above Limits
Sulfur Dioxide Allowance Price (2000)	($/Ton)	211	284 [1]	409
Air Quality Combined • Clean Air Capital Cost • Air Toxics • Visibility • Ozone		No Additional Controls [1]	• Low NO_x Controls at Cumberland and Gallatin • Reduced Hg by 2010 • SNCR by 2010	• Low NO_x Controls at Cumberland and Gallatin • Reduced Hg by 2002 • SNCR by 2002
Water Quality Combined • Thermal Plant Regulations • Aquatic Biota • Toxins • Water Flow Alteration • Toxics, Bioaccumulation, pH		No Additional Regulations [1]	• Cooling Towers at All Steam Plants in 2002 @ 130 $/kW (1994$)	• Cooling Towers and Additional Runoff Control @ 190 $/kW in 2002 (1994$)
LOAD REQUIREMENT				
Load Growth	(%) 1994-2000 2000-2020	0.0 0.0	2.2 [1] 1.9 [1]	3.4 3.2
Interruptible Load and Emergency Appeals (2000)	(MW)	700	1900 [1]	2560
Competition with Neighbors, Open Access, and Fence - Growth	(%) 1994-2000 2000-2020	0.9 1.0	2.2 [1] 1.9 [1]	2.1 2.2
SITING		No Restrictions [1]	No Central Station Options	No Central Station Options
DEMAND-SIDE MANAGEMENT EFFECTIVENESS	(MW) Savings in Year 2010	3124	5494 [1]	8219
NEW TECHNOLOGY COST		Reduce Cost 50%	Reference [1]	Reference
COMBUSTION TURBINE				
Reliability	(%)	68	84 [1]	90
Plant Life	(Years)	25 Years [1]	30 Years	30 years
Plant Efficiency	(Btu/kWh)	9,000	10,500 [1]	12,000
DISCOUNT/INTEREST RATE	(%)	6	8 [1]	12

[1] Indicates value in Energy Vision 2020 Reference

hydro generation over the 100-year period would indicate a 10 percent likelihood of the energy output being around 13 billion kilowatt-hours or less, and a 10 percent chance the energy output could be 22 billion kilowatt-hours or higher. The mid-range forecast of around 18 billion kilowatt-hours has a 50 percent chance of the output being lower or higher. While hydro variation may occur for several years at a time, it is less likely to remain consistently at a high or low level over the long term. Thus, this uncertainty is more significant to short-term plans of, say, five years or less.

Although not being treated explicitly, another scenario that could create a range of outcomes in long-term hydro generation is the TVA use and control of the Cumberland River Projects.

TVA could lose some of the Cumberland Projects due to license extension requirements. TVA could gain hydro output through negotiated control of additional segments of the river generating output operated by Southeastern Power Administration (SEPA).

ISSUE 2: COAL

Below are various uncertainties involving TVA's coal usage.

Issue 2.1: Capital Additions and Improvements for New Coal Capacity

Capital additions and improvements are betterments of plants. They are expected to have a long life and are therefore capitalized. In contrast, the cost of current repairs and minor replacement is charged to operating expense.

The medium estimate for a mature commercial supercritical pulverized coal plant (4 units of 300 megawatts each) is $13.6 per kilowatt per year. For the range of values, the low is $12.5 per kilowatt per year and the high is $14.8 per kilowatt per year (This is in 1994 dollars.)

Issue 2.2: Coal and Combined Cycle Operating and Maintenance Costs

Operating and maintenance costs for fossil units are divided into fixed and variable components. Variable operating and maintenance cost is the incremental cost of generation incurred only if the unit generates. Fixed operating and maintenance cost at an operating unit is incurred whether or not the unit operates. The mid-range of both the fixed and variable operating and maintenance costs escalate using standard TVA escalation with a 1 percent improvement (fiscal year 1999 to fiscal year 2020). The low case includes a 2 percent improvement, while the high case includes a 1 percent increase (fiscal year 1999 to fiscal year 2020). For the mid-range case, the fixed operating and maintenance cost is $21.7 per kilowatt per year of dependable capacity (in 1994 dollars) and the variable operating and maintenance cost is 0.39 mills per kilowatt-hour (based on 1994 dollars). The same base is used for both low and high, while the standard TVA escalation rate with a 2 percent annual improvement for the low, and a 1 percent annual increase in escalation is assumed for the high.

Issue 2.3: Plant Life Extension

Additions and improvements are made to the existing fossil units at a steady rate to ensure the units continue to operate into the future. One range of uncertainty would be a TVA decision to retire a coal facility that is low in the loading order. For purposes of illustration, the Widows Creek Units 1-6 were retired, representing 750 megawatts of capacity that must be replaced.

Issue 2.4: Reliability (Coal and Combined Cycle Units)

The reliability of a generating unit is a measure of the hours during a year that the unit is available to operate and includes the possible reduction in full unit output due to derating conditions. This excludes the time a unit is out for scheduled maintenance.

An unscheduled outage may be defined as a total loss of generation due to a failure of a component essential to unit operation. A derating is a failure of a component that may only reduce the amount of generation available from the unit. Reliability measure of equivalent forced outage rate is made up of these two factors.

The mid-range forecast is 9 percent; while the high is 20 percent, and the low is 6 percent.

Issue 2.5: Fuel Cost (Coal)

Fuel prices for coal facilities are based on FOB mine price projections combined with transportation rates to determine delivered price forecasts to each TVA stockpile. Delivered fuel price forecasts of three independent consultants have been averaged to obtain the TVA coal spot price forecast. These consultants are Energy Ventures Analysis, Inc., Hill and Associate, Inc., and J. D. Energy, Inc.

For a new coal facility at Tennessee River Mile 160 for a 5.0 pound sulfur dioxide per million Btu coal plant, the mid-range price projection (in 2000) is 109 cents per million Btu with a 3.3 percent escalation rate. The low forecast is projected to be 100 cents per million Btu with a 2.8 percent escalation. High projection is 121 cents per million Btu with 4.0 percent escalation.

For TVA's existing coal facilities, the mid-range price forecast is 131 cents per million Btu with a 3.5 percent escalation rate. The low forecast is 119 cents per million Btu (3.0 percent escalation), and the high forecast is 146 cents per million Btu (4.1 percent escalation).

FIGURE T8-24. **Range of Values for Coproduct**

Year	Low $/Ton	Medium $/Ton	High $/Ton
1995	82.7	237.4	290.0
1996	84.4	242.1	295.8
1997	86.0	247.0	301.8
1998	87.8	251.9	307.8
1999	89.5	256.9	314.0
2000	91.3	262.1	320.2
2001	96.0	282.3	352.9
2002	99.7	299.6	383.1
2003	103.3	318.0	416.1
2004	107.2	337.1	450.8
2005	109.0	351.4	481.0
2006	113.2	373.1	522.3
2007	116.9	394.6	564.5
2008	120.0	414.3	606.4
2009	124.4	439.2	657.6
2010	127.9	463.0	708.9
2011	133.8	495.6	775.3
2012	139.2	527.3	844.2
2013	143.3	555.2	909.0
2014	147.6	584.9	979.6
2015	151.1	613.5	1051.1
2016	155.1	643.6	1127.9
2017	158.1	673.0	1206.8
2018	161.4	702.6	1288.4
2019	163.8	729.9	1369.2
2020	166.4	758.7	1456.5

The viability of coal gasification combined cycle projects depends on the value of the coproducts. This chart shows the range of values for a byproduct of coal gasification.

Issue 2.6: Market Price of Coal Gasification – Combined Cycle Coproduct

Coal gasification technology is commercially utilized for producing synthesis gas for chemical applications including the production of ammonia, methanol, and methyl tertiary butyl ether (MTBE). The viability of coal gasification combined cycle projects depends on the value of the coproducts. Much of the gas produced is used up producing the coproduct, and the remaining low heat value gas is used to produce electricity. The following estimate in *Figure T8-24* is representative of various coproducts for screening purposes.

ISSUE 3: COMBINED CYCLE FUEL PRICE – NATURAL GAS

For the year 2000, the forecast for natural gas prices at a new combined cycle facility at Tennessee River Mile 160 is 342 cents per million Btu. This is expected to escalate at 5.3 percent per year. In preparing this medium natural gas price forecast, TVA relied on forecasts by Energy Ventures Analysis, Inc., Jofree Coporation, and ICF Resources.

The low and high values are 256 cents per million Btu with a 2.4 percent escalation and 418 cents per million Btu with an escalation rate of 7.9 percent. The high and low forecasts for gas prices were derived using several nationally recognized forecasters such as Gas Research Institute, American Gas Association, DRI/McGraw-Hill, and the Energy Information Administration.

ISSUE 4: NUCLEAR

Below are various uncertainties relative to TVA's use of its nuclear facilities.

Issue 4.1: Nuclear Moratorium

Issues that affect nuclear production include those events that alter the perception or physical capability of these facilities.

A major event either industry-wide or world-wide could cause a partial or complete shutdown of all nuclear units. Similarly, an event could create a shutdown of a specific unit type or vendor type for a period of time.

The range of outcomes assumed here are from the reference forecast to a shutdown of all nuclear units on the TVA system in fiscal year 2006.

Issue 4.2: Return to Service or Commercial Operating Dates on Nuclear Units

A range of operating dates are 12- to 36-month delays beyond the base for all the nuclear units beginning production after Watts Bar Unit 1.

Issue 4.3: Nuclear Capacity Factor

Capacity factor, the percentage of actual power generated compared to its maximum potential generation, is an uncertainty that impacts cost per kilowatt-hour of the nuclear facilities, as well as total production cost. The leading contributor to lost generation, or capacity factors less than 100 percent, for the nuclear industry as a whole is refueling, during which time the unit is unavailable for power generation. Additional lost generation may occur during operations due to testing, equipment maintenance, or other outages.

In this evaluation the mid-range capacity factor for nuclear units is 67 percent, with a low of 55 percent and a high of 86 percent based on TVA historical information and industry projections.

Issue 4.4: Nuclear Operating Cost

Operating costs cover those expenses incurred over the operating life of the unit. Nuclear costs are grouped into four categories: operating and maintenance, capital additions and improvements, fuel, and decommissioning. Operating and maintenance costs for nuclear units are projected in the medium case to be $69 per kilowatt of dependable capacity based on TVA's experience at the operating nuclear units since 1989. Nuclear operating and maintenance costs are driven by staffing levels. Typically, two-thirds of the total operating and maintenance budget goes directly to paying salaries, expenses, and benefits. Industry operating and maintenance costs escalated during the 1980s at rates in excess of general inflation as plant staff and contractors were added to respond to new regulatory requirements. The level of new regulations has dropped dramatically in the past five years, however, and the rate of operating and maintenance cost increases has likewise dropped. The nuclear industry has developed a strategic plan for reducing costs at operating units while still maintaining high levels of safety and performance. The trend in the nuclear industry is clearly toward smaller plant staffs, and a reduction in operating and maintenance cost is expected to follow. Industry targets for staffing levels at 2-unit sites like Sequoyah, Watts Bar, and Bellefonte is 0.5 persons per installed megawatt. This staffing level would result in operating and maintenance cost of about $55 per kilowatt per year, and this is used as the low value, with the high value at $83 per kilowatt per year. These estimates would escalate at 4.5 percent annually.

Issue 4.5: Nuclear Fuel Cost

TVA cost for nuclear fuel consists of two components; sunk cost and incremental fuel costs.

Sunk Cost of Fuel

TVA accumulated a uranium inventory during the 1980s of about 11 million pounds due to plant deferrals/cancellations and the 1985 extended outage. Interest on this inventory was capitalized throughout this period. The resulting high book value of uranium is driving TVA nuclear fuel costs. TVA is considering a write-off of the excess book value of uranium. This must be done if fuel costs are to be competitive before the inventory has been used. Barring write-off action, the existing inventory will affect fuel costs through 2001. Other actions have been initiated to reduce fuel costs, including renegotiation of contracts that will save approximately $70 million over the term of the contracts, loaning uranium from inventory, and utilization of fuel delivered for Watts Bar and Bellefonte in the operating plants at Browns Ferry and Sequoyah where practical, and purchasing enrichment services on the spot market at discounts of 30-35 percent relative to current term contracts. However, the effect of these other actions is small compared to the uranium book value.

Sunk cost is made up of two components: excess interest (approximately $1 billion dollars) and excess uranium inventory (approximately $400 million).

Incremental Cost

Incremental cost of nuclear fuel is the cost that TVA would pay today to replace the fuel. For Energy Vision 2020 considerations, TVA's nuclear plant fuel costs are based on an average incremental fuel cost for each of the nuclear plants. The incremental nuclear fuel costs (in 1994 dollars) are:

- Pressurized Water Reactor Fuel (Sequoyah, Watts Bar, and Bellefonte)—41.4 cents per million Btu
- Boiling Water Reactor (BWR) Fuel (Browns Ferry)—41.7 cents per million Btu

Escalation of Nuclear Fuel Cost

The nuclear fuel escalation rate may be affected by a number of factors including the general inflation rate, availability of nuclear fuel, demand for conversion, enrichment, and fabrication services, as well as spent fuel disposal costs.

For the next 30 years, abundant supplies of reasonably priced U_3O_8 will be available. The primary sources of supply will be inventories, production of existing projects, and known reserves, along with substantial quantities obtained from the nuclear weapon dismantlement program. In addition, enrichment and fabrication capacity exceeds demand. This situation is expected to continue for the foreseeable future.

Based on these considerations, nuclear fuel is expected to escalate at a rate equal to or less than general inflation during the period of 1995-2020. Energy Vision 2020 assumes escalation equal to general inflation. With a medium escalation forecast of 2.5 percent, the low is projected at 2.0 percent, with a high escalation forecast of 3.5 percent.

Issue 4.6: Spent Fuel Storage

A nuclear plant uses around 20 tons of fuel annually. A very small percentage of nuclear waste remains radioactive for thousands of years. The Nuclear Waste Policy Act of 1982 established a program to build a national underground high-level waste repository early in the next century. Currently a fee of $1 per megawatt-hour is collected to pay the Department of Energy for the disposal site. A high range is $2 per megawatt-hour.

Issue 4.7: Nuclear Additions and Improvements Costs

The cost of modifying an operating unit is a capital cost aggregated under the term additions and improvements. Modifications to nuclear facilities are driven by three causes:

- Implementation of regulation-driven modifications
- Facility improvements to increase reliability and capacity
- Routine replacement of existing capital equipment

During the 1980s, most modifications were driven by new regulations, many of which were issued following the 1979 Three Mile Island accident. A number of these regulations involved expensive modifications to plant systems and equipment. In recent years, however, new regulations have decreased, and in general, have had a lower financial impact. This trend reflects the maturing of the nuclear industry and increased knowledge about nuclear safety.

Nuclear industry additions and improvements costs dropped significantly with the completion of regulation-driven modifications. By 1990, the average rate of additions and improvements expenditure had been reduced to approximately one-quarter of the 1984 to 1986 high. While some regulation-driven changes continue to occur, utility investments are now more focused on general maintenance and performance upgrades.

TVA's additions and improvements costs are projected to be typical of the industry. Energy Vision 2020 assumes additions and improvements costs of $20 million per site per year plus $5 million per unit per year (in 1994 dollars). Additions and improvements for Bellefonte are $12 per kilowatt per year for the mid-range with a low of $9 per kilowatt per year and $19 per kilowatt per year for the high. Escalation is expected to be 4.5 percent.

Issue 4.8: Capital Cost-Bellefonte Unit 1

TVA and other nuclear engineering and construction firms (e.g., NUS Corporation, United Engineers & Constructors, Fluor-Daniel, MPR Associates, B&W Nuclear Services, and Stone and Webster Engineering Corporation) extensively reviewed the status and condition of the existing construction. Many of TVA's problems on other units were traced to the lack of good configuration control during the construction process. A detailed effort was conducted to firmly establish the licensing basis for the site. TVA then compared design records for the plant with construction records to confirm consistency. These records were then compared to actual construction, demonstrating that:

- The records existed and were retrievable.
- The records were consistent.
- The construction matched the design records.
- Design and construction were consistent with regulatory requirements.

Independent inspections performed by the Nuclear Regulatory Commission have confirmed these conclusions. Equipment and system inspections have shown that the construction quality problems encountered at other TVA facilities do not exist at Bellefonte. Agreements were reached with the Nuclear Regulatory Commission regarding the work required to resolve 14 potential regulatory concerns, representing the bulk of any remaining regulatory risk.

Consequently, the effort required at Bellefonte is largely associated with completing the remaining 12 percent of the construction work. A review of the remaining work shows that a substantial portion of remaining construction is associated with "close-out" type efforts (e.g., applying insulation and painting). Good record quality and frequent plant inspections allow this work to be estimated with a high level of confidence. In developing completion estimates, engineering firms with recent experience in completing other nuclear projects (e.g., Comanche Peak) were heavily involved to ensure that all necessary work was identified. In addition, TVA's experience in completing Watts Bar Unit 1 was fully considered. Bellefonte's completion plan utilizes the same "engineering-first" approach discussed previously.

The cost estimate to complete Bellefonte has been reviewed 21 times to date and provides a very definitive statement of the work scope required to place that unit in service. This definitive knowledge of scope positions the Bellefonte project to exercise several alternative contracting structures, including fixed price/lump sum contracting of facility completion.

More than half the cost to complete Bellefonte is not associated with construction but to put a well-trained operating staff in place for unit start-up. Because staffing and operator training have been done many times before in the industry, they can be estimated with a high level of confidence. Extensions in the start-up schedule can affect the cost to these items, in that the staff costs will continue to be carried as a capital expense until the unit enters service.

Estimates were also developed for the cost to complete Watts Bar Unit 2 and the cost to recover Browns Ferry Unit 1. These estimates were developed using a process similar to that used for Bellefonte in which a detailed examination was made of the work required and experience with previous projects fully considered.

Other Cost Uncertainty Considerations

While every effort has been made to provide the most accurate cost and schedule estimates possible, some uncertainty still remains. The process used to estimate costs captures the effect of previous contributors to cost increases by using actual experience as the estimate basis. Management representatives were involved in reviewing all cost estimates to ensure that the experience from each project was reflected in each new estimate. Work plans were reviewed in detail and the level of certainty assessed with the

FIGURE T8-25. **Cost to Complete Nuclear Units**

	Millions $			
	Bellefonte 1	Bellefonte 2	Browns Ferry 1	Watts Bar 2
Low	1311	912	1187	1097
Medium	2622	1824	2374	2194
High	3470	2420	3150	2910

This chart shows the low, medium, and high range of cost estimates to complete these nuclear generating units.

cost estimated for each line item. Management reserve requirements were determined based on results of this study and included in the base cost estimate. The management reserve requirement ranged from 10 percent to 30 percent depending on the level of risk.

To accommodate uncertainties not otherwise covered, adjustments are applied to the detailed engineering cost estimates based on the errors in past cost forecasts. The low completion cost estimates are the detailed engineering cost estimates themselves with the management reserve included.

The medium and high estimates are based on the low estimates adjusted for past errors in forecasting nuclear plant construction costs. The historical record of forecasting nuclear plant construction cost for plants in the United States and in the TVA region was reviewed for accuracy. The general conclusion of this review was that for plants 4 to 6 years from completion, the actual cost to complete was significantly greater than the forecast or estimated cost. The actual costs to complete were generally 100 to 200 percent greater than the forecast costs.

TVA's nuclear project cost estimate accuracy since 1987 was also reviewed. This review indicates that the error in forecasting future nuclear plant costs ranged from 100 percent to 230 percent. From 1987 to 1994, the average error in estimates made 4 to 6 years before completion was approximately 165 percent.

The major dilemma facing forecasters of nuclear plant completion costs is to what degree past forecast errors have been corrected in current estimates. The low forecasts assume that the latest engineering cost estimates are accurate. The high estimates, which use a multiplier of 2.65, assume that forecast errors will continue in the future at the same level experienced in the past. The mid-range or medium estimate of the cost to complete assumes that the future forecast error will be somewhat less than historical errors. Past forecast errors were due, at least in part, to rapidly changing regulations and the difficulty in managing large nuclear construction projects. Future errors could therefore be reduced if regulations were more stable and with improved construction project management. The medium forecast is based on the assumption that future forecast errors will match the minimum historical TVA error, which is approximately 100 percent. Thus, the medium forecast in *Figure T8-25* is twice the low estimate.

There is likewise a range of capital cost estimates for completion of the nuclear units. This range is shown in millions of dollars in *Figure T8-25*.

Issue 4.9: License Extension

The operating licenses for Browns Ferry Units 1, 2, and 3 currently expire in 2013, 2014, and 2016, respectively. The Nuclear Regulatory Commission, however, issued regulations establishing the requirements for obtaining an extension in the operating license for up to 20 additional years. The original rule issued by the Nuclear Regulatory Commission in 1991 is currently being revised and is expected to be finalized in mid-1995.

TVA, along with other utilities and industry organizations, has completed some preliminary review of the potential for extending operating licenses. No technical issues have been identified that would preclude license extension on Browns Ferry. In fact, Browns Ferry provides some unique benefits for license extension as a result of the extensive work being done to recover these units.

While it is difficult to accurately estimate the cost and schedule requirements for obtaining a license extension in advance of final issuance of the rule, the cost appears to be low (potentially on the order of $10 million).

Given the status of the rule, however, it is impossible to predict with certainty the success of an application for license extension at this time. Therefore, Energy Vision 2020 considers cases where license extension does not occur, as well as cases in which it does occur.

Issue 4.10: Nuclear Summer Limits – Temperature Water Discharge

Cooling towers are provided to support operation of the Sequoyah and Browns Ferry Nuclear Plants during periods of high river water temperature. Nonetheless, on rare occasions during extremely hot conditions, these units may be required to reduce generation. A loss of 150 megawatts is considered in the Energy Vision 2020 analyses.

Issue 4.11: Decommissioning Costs

At the end of the facility's operating life, the reactor plant must either be dismantled or placed in a state of protective storage. A safe storage mode would be followed by removal of the reactor plant after a period of dormancy. The decision as to the mode of decommissioning will be influenced by a number of factors pertinent at the time of final plant shutdown. These factors include

FIGURE T8-26. **TVA Estimates of Nuclear Plant Decommisioning Cost [1]**

Value	Pressurized Water Reactors (PWRs)	Boiling Water Reactors (BWRs) [5]
Low [2]	$200 Million per Unit	$250 Million per Unit
Medium [3]	$300 Million per Unit	$350 Million per Unit
High [4]	$600 Million per Unit	$700 Million per Unit

1 Estimates are based on the DECON option.
2 The low values for the PWRs and BWRs are based on the Nuclear Regulatory Commission formula of $105 and $130 million (in January 1986 dollars), respectively, escalated to 1994 dollars.
3 The medium values represent the average of the industry estimates escalated to 1994 dollars.
4 The high values were calculated at twice the industry average.
5 The higher BWR cost reflects a margin for potential additional decommissioning cost associated with a BWR unit.

TVA has developed low, medium, and high estimates for decommissioning its nuclear power plants. The NRC formula for pressurized water reactors and boiling water reactors was used in developing the estimates.

potential use of the site for other purposes, cost of the alternatives, minimization of occupational radiation exposure, availability of low-level disposal space, availability of a high-level waste repository or spent fuel monitored retrievable storage facility, regulatory requirements, and public opinion.

As shown in *Figure T8-26*, TVA has developed low, medium, and high estimates for decommissioning its nuclear power plants. In developing the estimates, the Nuclear Regulatory Commission formula for Pressurized Water Reactors (PWRs) and Boiling Water Reactors (BWRs) was used to determine the low values. A medium value was determined from the range of current industry estimates to be $300 million (approximately 90 percent of the industry estimates are lower than this value). The high value was developed by doubling of the medium estimate. The high cost estimate, which is double the medium estimate, considers the uncertainties of decommissioning, including spent fuel disposal, and low-level waste disposal.

Some recent industry estimates for decommissioning are as high as a billion dollars, due primarily to high estimates for off-site storage and management of spent fuel and other high-level wastes. TVA's plan for spent nuclear fuel is to store it on-site at the plant locations where it is generated until the Department of Energy (DOE) accepts physical custody by shipment off-site to a monitored retrievable storage facility or to an underground repository for ultimate disposal by burial. TVA has sufficient outside site area at each of its nuclear facilities to store any high-level waste associated with decommissioning activities. This would be done, possibly in containers provided by the Department of Energy, until the federal government is able to fulfill its contractual obligation to move the fuel off-site.

ISSUE 5: COGENERATION

Below are uncertainties related to cogeneration.

Issue 5.1: Cost of Cogeneration

Cogeneration projects are being developed throughout the United States. As replacement power, capital cost of construction is an uncertain issue that is treated in a resource plan. In this case, the capital cost range is from a base of $175 per kilowatt for the medium with a 10 percent reduction for the low and a 50 percent increase projected for the high.

Issue 5.2: Available Amount of Cogeneration

The amount of cogeneration may be limited, especially if it is located outside the Tennessee Valley. A limit of 2,000 megawatts is placed on cogeneration capability to study the sensitivity of results of this issue.

ISSUE 6: TRANSMISSION

Below are three uncertainties that involve transmission issues.

Issue 6.1: Transmission-Related Electromagnetic Fields

Concern over possible health effects due to electromagnetic fields (EMF) could cause difficulties in siting transmission lines. To lower magnetic field levels, extensive reconstruction of existing transmission lines would be required, and new lines would be much more expensive.

Several methods that can be used to reduce EMF include:

- Building transmission lines underground with appropriate protection
- Increasing ground clearance of overhead lines
- Installing reverse-phasing (double circuit) lines
- Using photovoltaics, batteries, and other types of modular technologies at the customer level and thereby mitigating the need for transmission service

In Energy Vision 2020, the range of this uncertain parameter has been represented as follows: the low-range case is one in which no additional controls/modifications are required. The mid-range case is $50 million increase in the cost to build transmission for a greenfield site, while the high is represented by a 50 percent increase overall in transmission costs.

Issue 6.2: Wheeling Requirements

Transmission access (wheeling) involves allowing another utility company or retail customer access to the transmission system to send electricity from one utility to another utility. The rules of such access are being developed in response to the Energy Act of 1992. Wheeling requirements are subject to the availability

of the TVA system, good faith requests and responses, facilities upgrades and additions, scheduling and operations, losses, opportunity costs, etc. The wheeling rate being developed by TVA is comprised of three components: reactive power production, firm transmission service rate—base, and margin basis.

Issue 6.3: Transfer Limitations on Interconnections

Limitations on interconnections could cause two short-term responses. If Bellefonte is built, some excess energy may be available for export for a short period of time. This energy export could be limited under certain transmission scenarios. Second, reliability requirements could increase with reduced transfer capabilities, thus requiring replacement of capacity earlier if Bellefonte is canceled.

The limit on transfer capability is modeled in the uncertainty study through an increased reserve requirement.

ISSUE 7: PURCHASED POWER

Following are two uncertainties that involve purchased power.

Issue 7.1: Purchased Power Amount Available

The amount of power available from other utilities depends on the load and power supply situations of these potential suppliers and the timing of the need for TVA. While there is a mid-range of 1,500 megawatts of purchases available in the medium forecast, a range of 25 percent less or greater represents the low and high forecasts. Thus, the low range assumption is purchased power levels at 1,125 megawatts while the high range is 1,875 megawatts.

Issue 7.2: Purchased Power Price

In the year 2000, the purchased power projected prices are $56 per megawatt-hour with an escalation rate of 6.5 percent annually for the next five years. The low range is represented by a 2 percent reduction in escalation rates, while the high range is represented by a 3 percent increase in the escalation rates.

ISSUE 8: ENVIRONMENTAL QUALITY

The impact of future environmental issues is divided into several uncertainties for discussion.

Issue 8.1: Emission Caps on Carbon Dioxide

Carbon dioxide emissions are capped in the medium forecast at 1990 levels by the year 2002. The cost of additional emissions above 1990 levels of 83 million tons are priced at $5 per ton.

For the more constrained projection, in addition to the medium limits, an additional constraint by 2010 is a ceiling of 80 percent of 1990 levels. Emissions over that ceiling are priced at $10 per ton. Escalation of these values from 1994 are at 4 percent.

Issue 8.2: Sulfur Dioxide Price Allowance

The price of sulfur dioxide emission allowances on the market will vary in the future. The medium projection of $284 per ton (in 2000) is projected to range from $211 to $409 per ton. By 2010, that range is $201 to $723 per ton with a medium of $321 per ton. Escalation beyond that period is 0 percent for the medium, with a range from -1 to +3 percent.

Issue 8.3: Environmental – Air

Figure T8-27 shows the air quality components of the environmental issue. Additional information on these environmental air uncertainties can be found in the Environmental Uncertainties Appendix.

Issue 8.31: Clean Air Capital Cost

Capital costs associated with compliance with TVA's Clean Air Strategy may vary. These capital projects help control sulfur dioxide, nitrogen oxides, and other emissions. The medium forecast is $210 million, with a low of $180 and a high of $236 million in the year 2000. These include expenditures at the majority of the coal-fired power plants.

Issue 8.32: Air Toxics

Issue 8.33: Visibility

Issue 8.34: Ozone

The above-named three issues have been combined into one control scenario with a range of possible costs to control the pollutants related to these issues.

The control of mercury is the key issue in air toxics; visibility is affected by "haze," and the requirements for the ozone

FIGURE T8-27. **Environmental – Air**

	Control Issue	Assumed Control Methods
Health-Air Toxics	Mercury	• Wet Scrubbers at Selected Units • Scrubbers at Selected Units • #2 Coal at Selected Units
Visibility	Haze (Sulfate)	• Wet Precipitators at Selected Units • SNCR at Selected Units
Ozone	Non-Attainment Areas • Nashville • Smoky Mountains • Further Nitrogen Oxides Limits	• SNCR at Selected Units

This chart shows the air quality components of the environmental issue.

FIGURE T8-28. **Environmental – Water**

Control Issue	Assumed Control Methods
Thermal Existing Plant Regulations	• Cooling Towers
Aquatic - Biota	• Closed Mode Operation and/or Cooling Towers
Water Toxins	• Mixing Zone Controls • Linkage Regulations
Water Flow Alteration	• Minimum In-Stream Flows
Water Toxics, Bioaccumulation, & pH	• Surface Water • Discharge (Eliminate)

This chart shows the issues and possible controls.

controls relate to non-attainment areas in Nashville and the Smoky Mountain regions.

Mercury can be controlled through expenditures to add wet precipitators and scrubbers. In addition, an incremental operating cost of around $2.5 per megawatt-hour will occur at selected plants in 2002. Haze is controlled through expenditures of $410 million capital and an incremental operating cost of $2 per megawatt-hour at Bull Run, John Sevier, and Kingston plants by 2002; with a moderate impact having control by 2012. Ozone can be enhanced through capital expenditures of $68 million plus an added $2 per megawatt-hour operating cost at Cumberland and Gallatin by 1996. A more stringent case would also require $93 million capital and a $2 per megawatt-hour operating cost increase at Cumberland, Gallatin, Bull Run, John Sevier, Kingston, and Widows Creek plants.

Issue 8.4: Environmental – Water

Figure T8-28 shows the issues and possible controls. Additional information on these environmental water uncertainties can be found in the Environmental Uncertainties Appendix.

Issue 8.41: Thermal Plant Regulations

Issue 8.42: Aquatic Biota

Issue 8.43: Water Toxins

Issue 8.44: Water Flow Alteration

Issue 8.45: Water Toxics, Bioaccumulation, and pH

These five issues have been combined into one control scenario with a range of possible costs to control these issues.

Thermal limits at existing plants can be met by adding cooling towers. Aquatic biota concerns can be met through operating in a closed mode or by adding cooling towers.

Water toxins can be reduced by implementing mixing zone controls or linkage regulations. Minimum in-stream flows would require expenditures and additional operating and maintenance costs to stabilize water flow.

Surface water discharges can be eliminated at a substantial capital cost and added operating cost to control toxics, bioaccumulation, and potential of hydrogen (pH).

ISSUE 9: LOAD REQUIREMENTS

The load requirements issue involves several uncertainties, which are addressed individually below.

Issue 9.1: Native Load Growth

Total demand for electricity is measured in peak load requirements and in annual energy requirements. The growth rates for the medium forecast of peak loads from 1994 to 2000 is 2.2 percent per year, with a low of zero percent and a high of 3.4 percent. These rates are calculated from a 1994 base peak load of 24,400 megawatts. The growth rates for the period 2000 to 2020 are 1.9 percent for the medium, with a low of 0.0 percent and a high of 3.2 percent.

Issue 9.2: Deliverability of Interruptible Load

Issue 9.3: Customer Response to Emergency Appeal

These two items are combined in the sensitivity analysis. The medium reduction in load requirements is 1,900 megawatts (in 2000) with a low forecast of 700 and a high forecast of 2,560 megawatts. These reductions in load are equivalent to reduced capacity reserve requirements. The low scenario increases desired reserve levels by around 4 percent with the high decreasing reserves by 2.5 percent.

Limited Interruptible Power (LIP) and Economy Surplus Power (ESP) contracts allow TVA to interrupt load if needed when peak loads occur on the TVA system. The frequency and amount of actual interrupted load may vary from the contracted amount for several reasons including the fact that the load under interruptible contract may simply not be engaged at the time of the peak load. A medium value for the year 2000 is 1,765 megawatts available to be interrupted, while a low of 700 megawatts and a high of 2,160 megawatts are forecast.

Voluntary public appeals may result in peak load reductions ranging from 0 to 400 megawatts with a medium forecast of 140 megawatts. Any reduction of peak load results in a lower probability of loss of load, which makes the power system more reliable and lowers desired reserve requirements.

Issue 9.4: Competition with Neighbors and Open Access

In recent years, the electric utility industry has undergone a fundamental change. The world of regulated monopoly is being replaced by a world of competitive pressures. Wholesale open access (the right of wholesale customers to buy power from generating utilities other than the one whose lines serve them) can be mandated by the Federal Energy Regulatory Commission (FERC). Retail firms, such as large industrial customers, are looking for the same privilege, and retail open access is beginning to be mandated by some state regulatory bodies. In a more competitive market, TVA's success as a generating company will be greatly affected by whether TVA is successful in being a low-cost provider.

TVA has incorporated these competitive assumptions into its forecasts. In the medium forecast, TVA will maintain its current territory and will not gain outside customers nor lose customers inside its service territory.

TVA's forecast price of electricity, discussed earlier, is expected to remain competitive with other utilities. Market and regulatory changes would have less impact in the medium case, than in the high or low cases. As a result, the net impact of competition in the medium forecast is an even balance of gains and losses of sales.

The prospect of increasingly competitive markets increases the uncertainty in the forecast. If TVA operates at lower costs than the competition, and regulations permit, TVA may have opportunities to gain customers. This is termed high competitive success. Likewise, if TVA is a higher cost producer than its competitors, it is likely to lose customers-described as low competitive success. Both cases assume that deregulation of the electric market continues. The high and low forecasts recognize the risks and opportunities of increased competition.

TVA analyzed competitive impacts for all sales. The effort was aimed at looking at the market rather than specific customers. In the low competitive success case, TVA will lose customers to competing electric utilities. In order to estimate the potential for losing sales to competition, TVA's customer survey—completed by many of the distributors of TVA power and directly served customers—was used to identify the amount of load that appeared to be at high risk.

In the high competitive success case, TVA will gain customers from its competition. To estimate the potential for this gain in the wholesale markets, loads of municipal and cooperative distributors in neighboring regions were used. The chance of gaining any distributor was partly influenced by the wholesale price paid by that distributor. Because a very large percentage of TVA's sales are wholesale, compared to neighboring utilities, the potential gain in the wholesale market in the high competitive success case was smaller than the potential loss in the low competitive success case.

For directly served customers, less specific information on nearby opportunities was available. Because TVA is surrounded by states with large industrial loads, a judgment was made that potential gain is higher than loss of industrial loads.

Wholesale and retail gains in load were assigned the highest probability for the low electric price forecast, making TVA more competitive. A more complete discussion of all uncertainties in the forecast can be found elsewhere in the uncertainty section.

ISSUE 10: SITING

Availability of sites to use in developing new power supply alternatives is important to enable capacity to be added as required. Some additional capacity could be constructed on existing sites. However, there are other issues such as water usage and environmental output that could reduce site potential. Two levels of assumptions are being analyzed for the sensitivity of this issue. In the reference case, there are no constraints. A second scenario assumes there are no central station options built; rather, future requirements are met by fuel cells, batteries, and other distributed generation sources.

ISSUE 11: DEMAND-SIDE MANAGEMENT (DSM) EFFECTIVENESS OR MARKET PENETRATION

High and low forecasts of the impact of demand-side management programs are evaluated to determine their sensitivity. The mid-range scenario reduces the peak load by 5,494 megawatts in the year 2010, while low reduction is 3,124 megawatts, and the high reduction is 8,219 megawatts.

ISSUE 12: NEW TECHNOLOGY COST AND AVAILABILITY

The cost of power produced using new technologies could be significantly impacted by breakthroughs in theoretical concept, design, materials, and other factors. In order to consider the potential effect of improvements in new technologies, a 50 percent reduction in the capital cost for generating options using new technologies has been included.

ISSUE 13: DYNAMIC OPERATING BENEFITS

Operating flexibility is defined as the benefit of a unit's operating flexibility in responding to system load variations. The ability to "turn down," for example, from a maximum capacity level to a minimal level over the period of the day as the load requirements decrease would have some benefit. Another alternative is to make expenditures in capital to enable generating equipment to respond appropriately to instantaneous and short-term conditions. These benefits are being determined in a separate sensitivity review outside this evaluation.

ISSUE 14: COMBUSTION TURBINES

The uncertainties pertaining to combustion turbines have been subdivided into the issues below.

Issue 14.1: Reliability of New Combustion Turbines

Reliability of peaking capacity is critical since the periods of time the units are called on are peak load hours. The medium projection for combustion turbine reliability is 84 percent, while a low of 68 percent and a high of 90 percent are evaluated.

Issue 14.2: Plant Life of Existing Turbines

Plant life of new capacity is assumed to be 30 years in the medium forecast. The low case assumes a life of 25 years.

Issue 14.3: Efficiency of Combustion Turbines

A range of efficiency is evaluated for the combustion turbines. A medium forecast of 10,500 Btu per kilowatt-hour is forecast. A "high value" or low heat rate of 9,000 and a "low value" or high heat rate of 12,000 Btu per kilowatt-hour is used to represent the range.

ISSUE 15: DISCOUNT RATE

ISSUE 16: INTEREST RATE

The discount rate (economic evaluation rate for investments or minimum attractive rate of return) is used to perform equivalence calculations (e.g., present value) necessary for comparing investment alternatives. The discount rate includes an amount for the time value of money and contains an implicit forecast of inflation expectations. A very basic consideration in selecting a discount rate is the cost of capital. No corporation can stay in business for the long term by investing at return rates less than the rates paid for funds. Keeping this in mind and noting the need to compare options with various forms and sources of financing, TVA has chosen the long-term interest rate as the discount rate to be used in Energy Vision 2020.

The interest rate TVA pays for funds is projected to rise somewhat over the next 10 years as worldwide demand for capital increases after the European and Japanese economies begin to recover. However, the moderate rate of inflation and declining federal budget deficit will keep rate increases moderate.

Since discount and interest rates must be set consistently, a medium discount and interest rate of 8 percent is evaluated with a low range of 6 percent and a high range of 12 percent.

Sensitivity of Resource Plans to Uncertain Parameters

Tornado diagrams are useful in determining the parameters that are significant in the decision-making process. This ensures that the most important parameters continue to be considered in the evaluation and allows less important parameters to be dropped from the analysis.

Figure T8-29 shows the most significant items as identified from the tornado diagrams.

To describe the tornado diagram, the following information can be used to illustrate development of the tornado diagram. The 30-year annual resource costs (discounted to 1994 at 8 percent) for the reference set of assumptions with Bellefonte completed are $93,382 million.

To determine the sensitivity of this resource plan to coal prices, the range of coal prices is used to develop total resource costs. As described in Issue 2.5, the low forecast is projected to be 100 cents per million Btu in the year 2000 with a 2.8 percent escalation. The high coal price forecast is 121 cents per million Btu with a 4.0 percent escalation. These are ranges around

FIGURE T8-29. **Uncertainties to Consider Further**

	EVALUATION CRITERIA			
Uncertainty	**Total Resource Cost**	**Rates**	**Debt in 2007**	**Carbon Dioxide Emissions**
Nuclear Moratorium	●	●	●	●
Nuclear Capacity Factor	●	●		●
Nuclear Operating and Maintenance Cost	?	●		
Nuclear Capital Cost	?	●	●	
Carbon Dioxide Compliance	●	●		
Environmental-Air	?	?	?	
Environmental-Water			●	
Load Growth	●	●	●	●
Competitive Success	●		●	●
Sites	●			
Coproduct Revenue	●	●		
DSM Effectiveness	?	●	?	?
Natural Gas Price	?	?		

Based on the tornado diagrams which follow, the most significant uncertainty items are shown here.

the medium forecast of 109 cents per million Btu and a 3.3 percent escalation rate.

With the low coal price forecast, the total resource cost becomes $93,103 million or a reduction in total costs of $279 million. If the high coal prices are assumed, the total resource cost increases to $93,951 million, which is an added cost of $569 million.

Thus, the variation in total resource cost due to the uncertainty in coal prices ranges from a reduction of $279 million to an increase of $569 million.

Results of the sensitivity evaluations are shown in *Figures T8-30* through *T8-37*. As described above, the tornado diagram shows the impact each uncertainty has on the basic nuclear completion decision.

Figure T8-30 shows the change in long-term total resource costs for a range on 35 parameters described earlier in this paper. Using zero as the base, the increases or decreases in total resource costs are shown as bars from zero.

Figure T8-31 shows the variation in the planning criterion of electric rates. *Figure T8-32* shows the change in debt in the year 2007 due to variations in the various parameters. Change in average annual carbon dioxide emissions are shown in *Figure T8-33*.

Since some of the uncertain items only make a difference under selected expansion strategies, *Figures T8-34* through *T8-37* show the impact of these "special issues" on the selected criteria.

Natural gas prices show up in a scenario in which natural gas-based capacity is constructed, e.g., combined cycle. The effectiveness of demand-side management programs is only important in scenarios in which demand-side management options are pursued. Finally, the value received from coproducts is important in the scenarios in which integrated gasification combined cycle plants with coproduction facilities are installed.

In the *Figures T8-34* through *T8-37*, these different alternatives are evaluated for the same four criteria—total resource costs, electric rates, debt, and average annual carbon dioxide emissions.

Conclusions

Issues that were carried forward into the Energy Vision 2020 evaluation are listed below:

- Load Growth
- Nuclear Issues
  - Capacity Factor
  - Operating and Maintenance Cost
  - Capital Cost
- Environmental Issues
  - Carbon Dioxide Compliance
  - Air and Water Environmental Controls
- Price
  - Natural Gas
  - Revenue from Coproduct (Combined Cycle)
- Demand-Side Management Effectiveness

Issues for which selected sensitivity evaluation can be performed include the nuclear moratorium and the inability to site central station generating capacity.

FIGURE T8-30. **Change in Total Resource Costs – Existing System, Nuclear Completion, and Coal-Based Expansion**

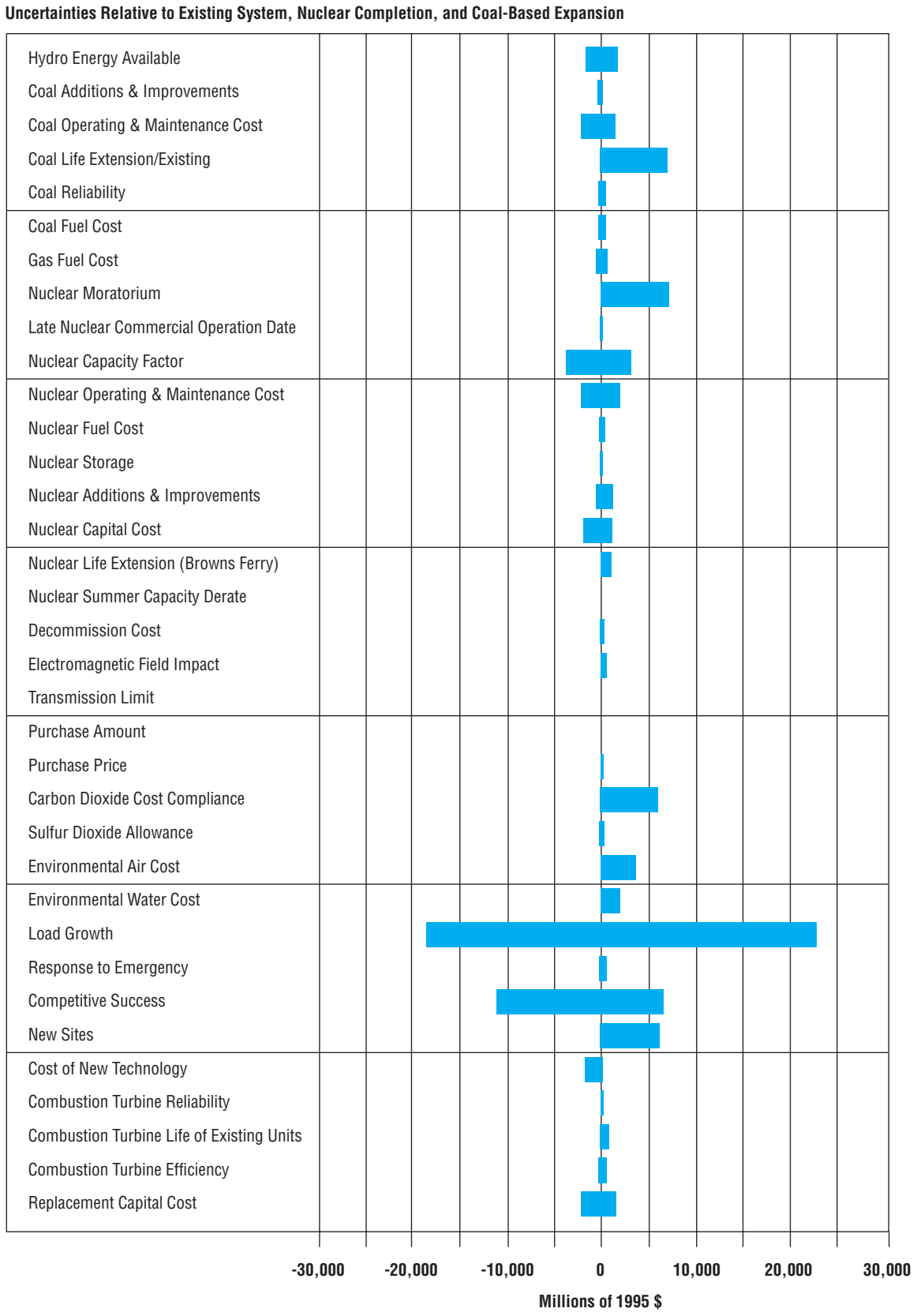


FIGURE T8-31. **Change in Electric Rates – Existing System, Nuclear Completion, and Coal-Based Expansion**

Uncertainties Relative to Existing System, Nuclear Completion, and Coal-Based Expansion

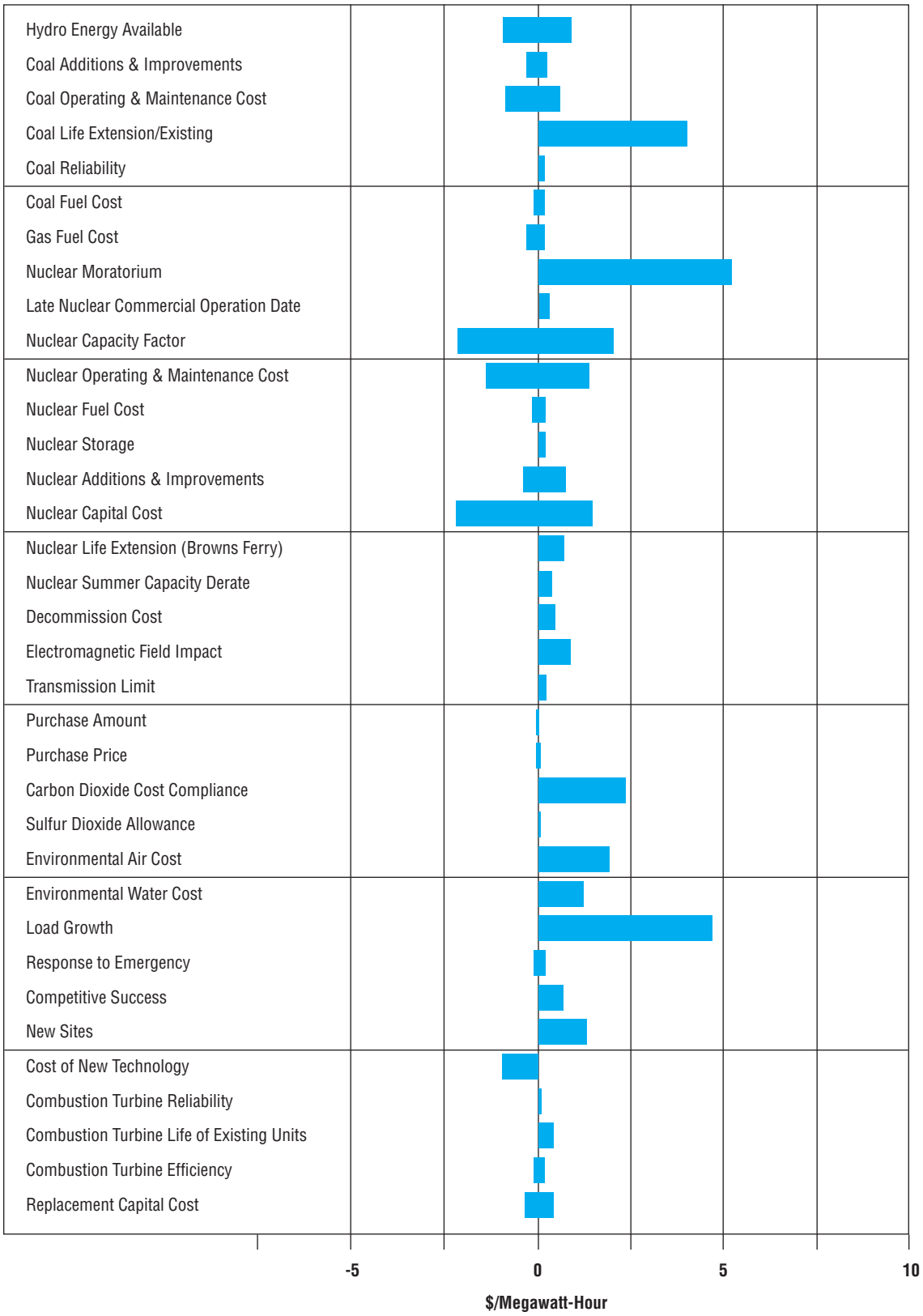


FIGURE T8-32. **Change in Debt in Year 2007 – Existing System, Nuclear Completion, and Coal-Based Expansion**

Uncertainties Relative to Existing System, Nuclear Completion, and Coal-Based Expansion

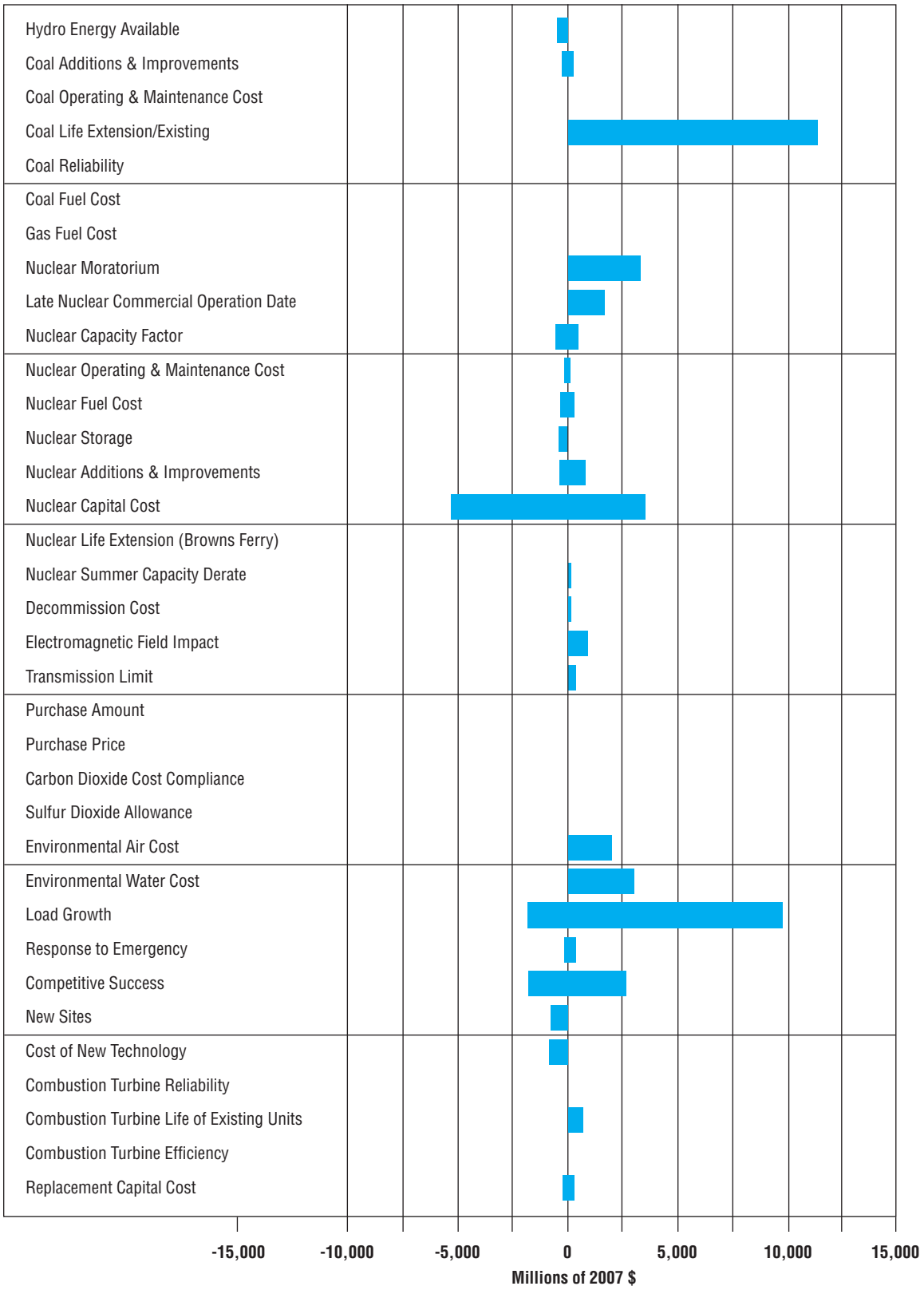


FIGURE T8-33. **Change in Average Annual Carbon Dioxide Emissions – Existing System, Nuclear Completion, and Coal-Based Expansion**

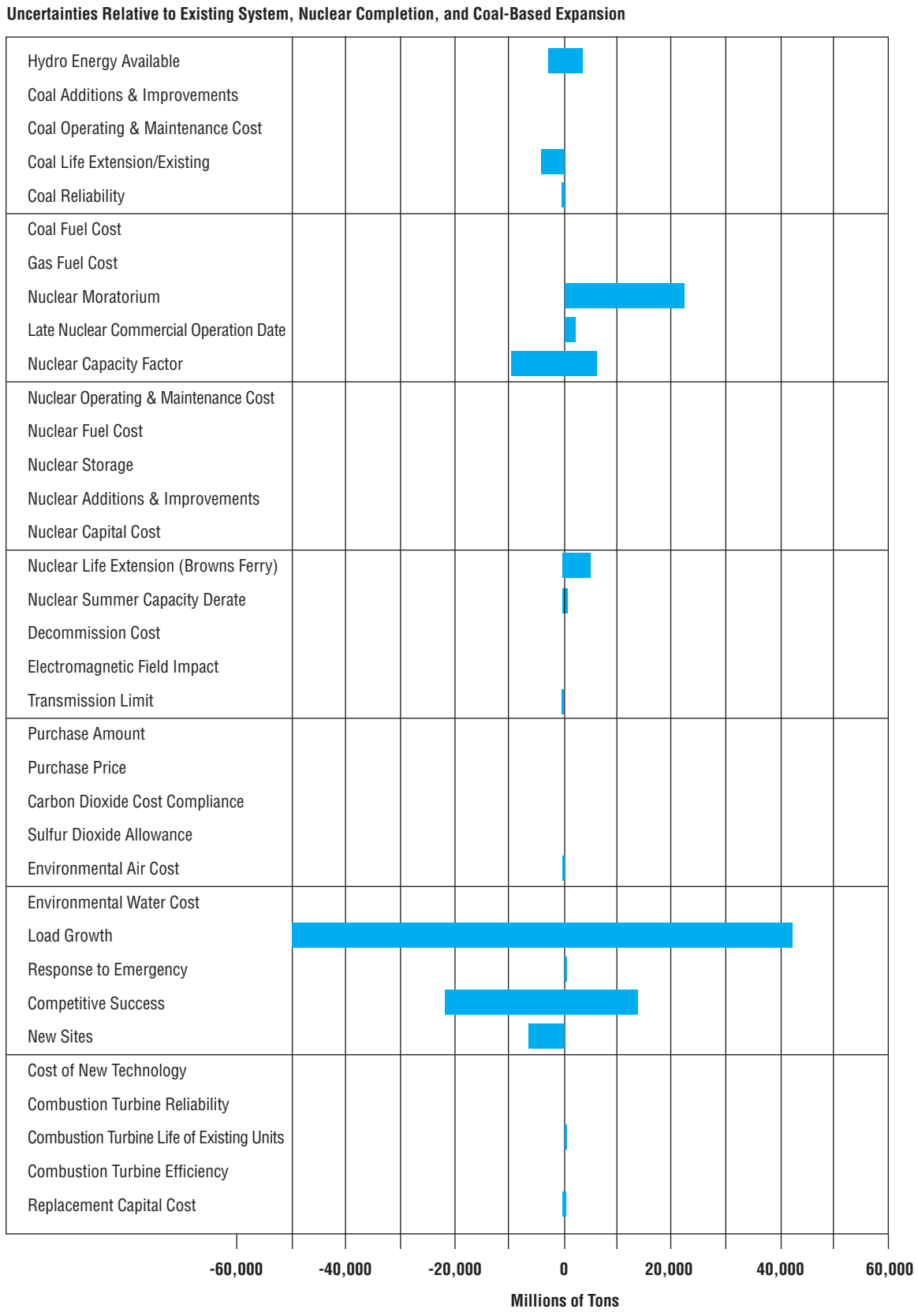


FIGURE T8-34. Change in Total Resource Costs – Other Expansion Options

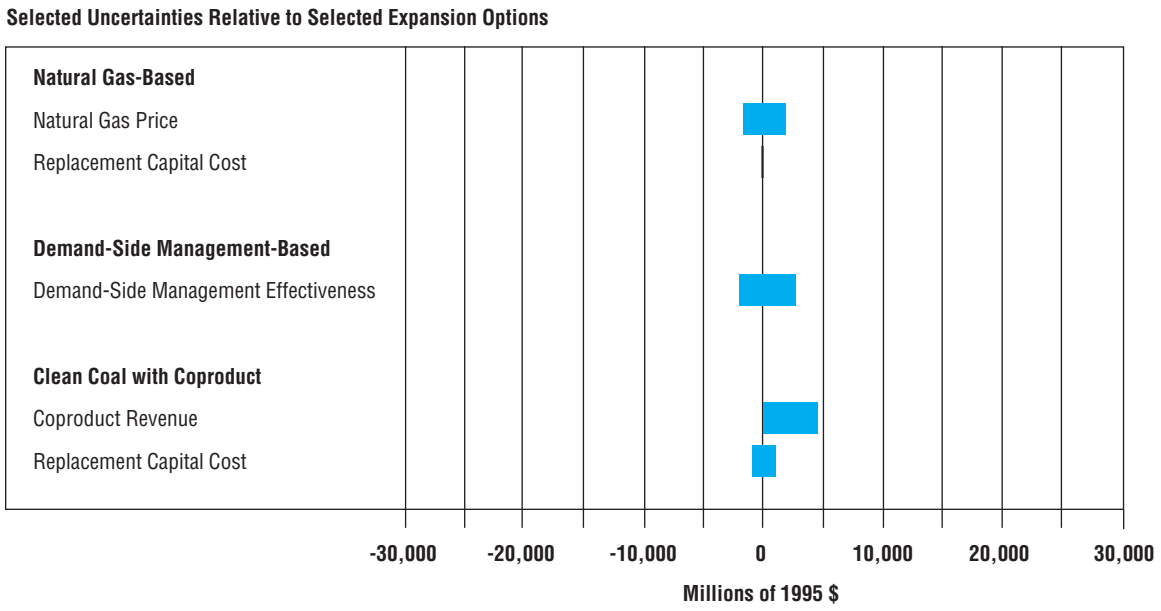


FIGURE T8-35. Change in Electric Rates – Other Expansion Options

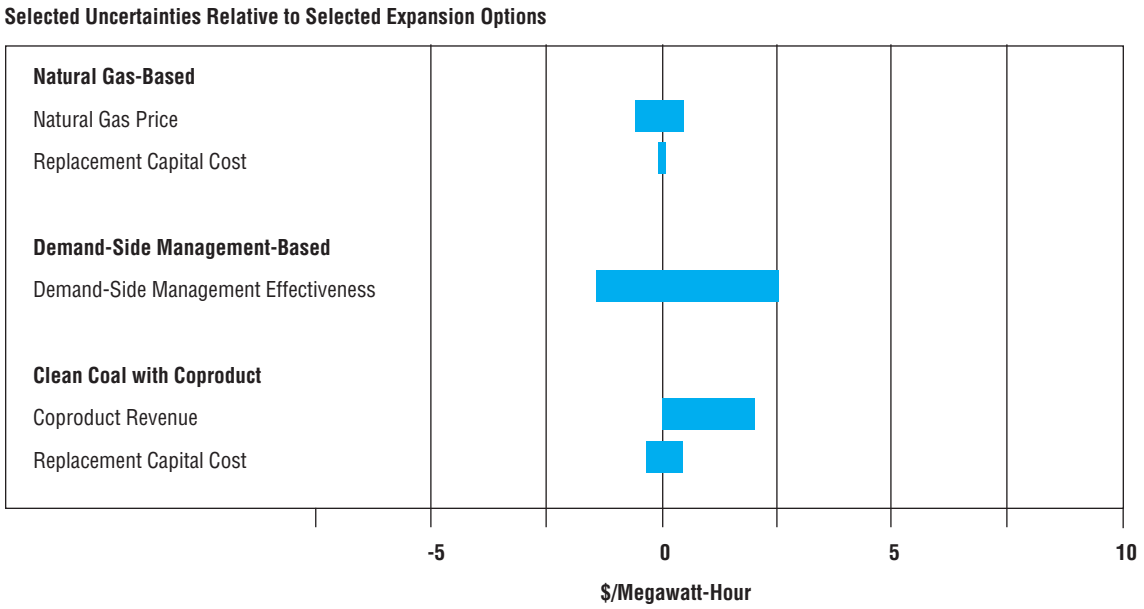


FIGURE T8-36. **Change in Debt in Year 2007 – Other Expansion Options**

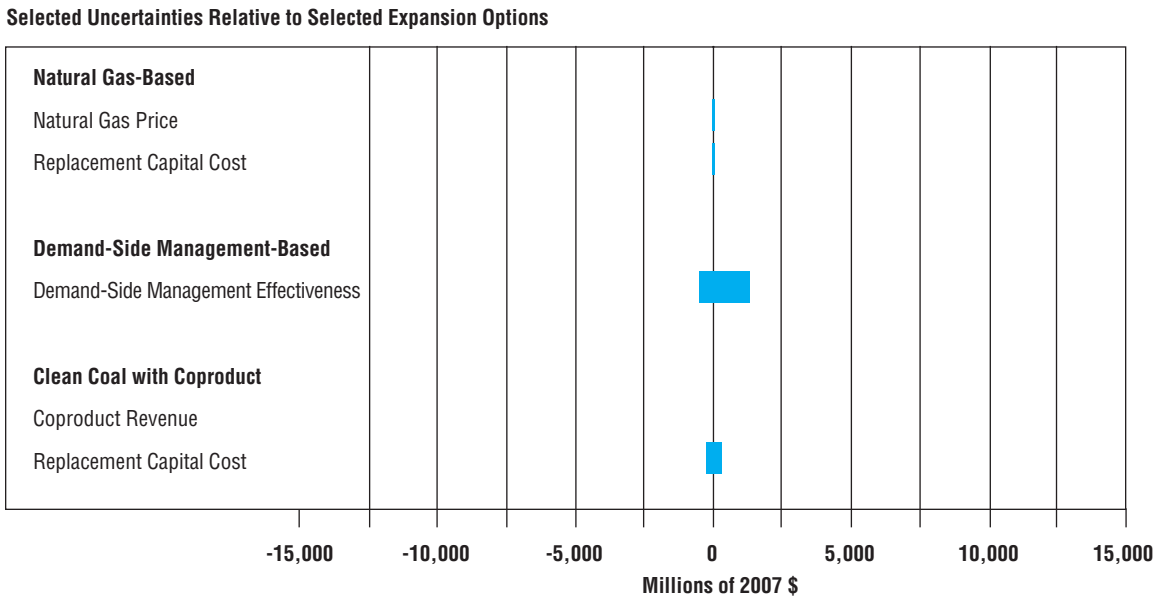
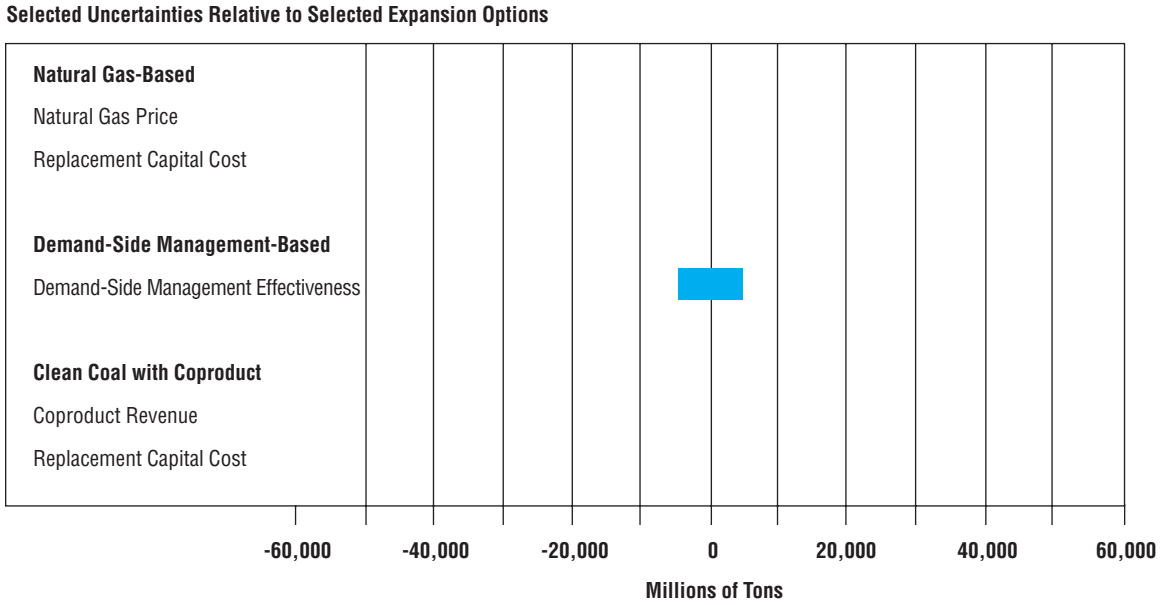


FIGURE T8-37. **Change in Average Annual Carbon Dioxide Emissions – Other Expansion Options**



ENVIRONMENTAL UNCERTAINTIES APPENDIX

Health — Air Toxics Uncertainty

Scenario 1: Utilities remain unregulated for air toxics
Impact on TVA: None
Probability of this scenario: 10 percent

Scenario 2: Environmental Protection Agency decides in 1996 to regulate air toxics from utility sources beginning in 2002. Equipment needed to control mercury will also control radioactive particulates and other heavy metals.
Impact on TVA: For Paradise 1-3, Cumberland 1-2, Widows Creek 7-8, and Allen 1-3 facilities, add wet precipitators at $50 per kilowatt. For other fossil plants, add spray dryer at $160 per kilowatt and switch to low sulfur coal of no more than 2 pounds per million Btu of sulfur dioxide emissions (some low sulfur coals are known to be low in toxic metals); add 0.4 cents per kilowatt-hour in variable operating and maintenance costs.
Probability of this scenario: 40 percent

Scenario 3: Same as scenario 2 except: Environmental Protection Agency decides in 2004 to regulate air toxics emissions beginning in 2010.
Impact on TVA: Same as scenario 2.
Probability of this scenario: 50 percent

Visibility — Acid Aerosols/Particulate Matter (PM) Uncertainty

Scenario 1: No new requirements
Impact on TVA: None
Probability of this scenario: 60 percent

Scenario 2: In 1997, visibility issues produce new regulations that require sulfate controls. TVA units put in service after 1962 are required to install Best Available Retrofit Technology (BART) by 2002. Best Available Retrofit Technology is determined to be 90 percent removal scrubbers. These are required on Bull Run, Paradise 3, and Colbert 5 plants.
Impact on TVA: Add scrubbers at capital cost of $200 per kilowatt, with increased operating and maintenance expense of 0.4 cents per kilowatt-hour.
Probability of this scenario: 30 percent

Scenario 3: In 2003, long-range transport and visibility issues produce new regulations that require sulfate and fine particulate controls by 2010. Best Available Retrofit Technology is determined to be 90 percent removal scrubbers and control of all particulates of 10 microns or less. Older units burning high or medium sulfur coal (in excess of 2.5 pounds per million Btu) are also required to reduce sulfur dioxide emissions and particulates of 10 micros or less emissions. These units add in-duct lime injection systems. (These controls will address the condensible portion of particulates of 10 micros or less. The mass portion of particulates of 10 micros or less should not affect TVA due to high efficiency of TVA's precipitators.)
Impact on TVA: Same as scenario 2. In addition, add in-duct lime injection systems at all unscrubbed units burning coal with 2.5 pounds per million Btu or greater sulfur dioxide emissions at cost of $15 per kilowatt and increased operating cost of 0.2 cents per kilowatt-hour.
Probability of this scenario: 10 percent

Health — Ozone Uncertainty

Scenario 1: No new requirements
Impact on TVA: None
Probability of this scenario: 10 percent

Scenario 2: In 1996, Nashville area is redesignated serious non-attainment for ozone, and modeling shows direct impacts due to nitrogen oxides emissions at Cumberland and Gallatin plants. Nitrogen oxides reductions are required at Cumberland and Gallatin plants by 1999. Low nitrogen oxides burners planned for installation at the Cumberland plant are judged inadequate to meet reduction requirements.
Impact on TVA: Selective non-catalytic reduction is added at Cumberland and Gallatin at cost of $20 per kilowatt. Variable operating and maintenance costs increase by 0.2 cents per kilowatt-hour at these plants.
Probability of this scenario: 30 percent

Scenario 3: In 2002, ozone non-attainment within the Great Smoky Mountains National Park forces additional nitrogen oxides reductions from sources within a 200-kilometer radius of the park. Requirements are met by adding selective non-catalytic reduc-

tion in addition to the previously installed low nitrogen oxides burners.
Impact on TVA: Additional controls are added to John Sevier, Bull Run, Kingston, and Widows Creek plants at $20 per kilowatt and 0.2 cents per kilowatt-hour variable operating and maintenance increase.
Probability of this scenario: 30 percent

Scenario 4: Combine scenarios 2 and 3
Impact on TVA: Combine impacts of scenarios 2 and 3
Probability of this scenario: 30 percent

General Air Regulation Uncertainty

Scenario 1: No new requirements that are independent of the other uncertainties described in this paper
Impact on TVA: None
Probability of this scenario: 90 percent

Scenario 2: New legislation in 2005 requires that all plants must meet all new source requirements, including new requirements for air toxics, by 2010. All plants must be equipped with 90 percent removal efficiency scrubbers and wet precipitators.
Impact on TVA: Add scrubbers to all unscrubbed units at cost of $200 per kilowatt. Add wet precipitator to all units at cost of $50 per kilowatt. Variable operating and maintenance increases at all plants by 0.4 cents per kilowatt-hour.
Probability of this scenario: 10 percent

Greenhouse Gas Emissions Uncertainty

Scenario 1: No greenhouse gas legislation
Impact on TVA: None
Probability of this scenario: 35 percent

Scenario 2: New legislation is passed in 1997 to stabilize greenhouse gas emissions at 1990 levels in the year 2002. Offsets for sequestration and "allowance trading" are allowed. Offsets are available at $3 per ton for the first million tons above 1990 levels, $5 per ton for any additional emissions.
Impact on TVA: Impose greenhouse gas emissions cap of 98 million tons of carbon dioxide equivalent beginning in 2002. Reduce value of sulfur dioxide allowances by 10 percent starting in 2002.
Probability of this scenario: 40 percent

Scenario 3: Same as scenario 2 except the emissions limit is reduced to 80 percent of 1990 levels in 2010. Needed offsets in excess of ten million tons cost $15.
Impact on TVA: Same as scenario 2 except the emissions cap drops to 80 percent of 1990 levels in 2010. The value of sulfur dioxide allowances drops 40 percent in 2010. Natural gas prices increase by 50 percent in 2010.
Probability of this scenario: 25 percent

Thermal Water Discharge Uncertainty

Scenario 1: Regulation of thermal discharges remains unchanged
Impact on TVA: None
Probability of this scenario: 80 percent

Scenario 2: All Section 316(a) variances that currently allow less stringent thermal limits are eliminated by 2002. Cooling towers operating in helper mode would be required at eight existing coal-fired plants, modifications would be required to the existing cooling towers at Sequoyah, and additional cooling towers would be required at Browns Ferry facilities.
Impact on TVA: Capital cost for cooling towers at existing coal-fired plants would be approximately $1.7 billion. Addition of cooling towers would also result in loss of 860 megawatts capacity and increased operating and maintenance cost of $3.9 million per year.
Probability of this scenario: 10 percent

Scenario 3: Mixing zones for surface water discharges are restricted to a maximum of 1,000 feet by 2002. Cooling towers operating in closed mode are required for all existing coal-fired plants and all new thermal plants to minimize mixing zone size. Modifications are required at Sequoyah and additional towers required at Browns Ferry facilities.
Impact on TVA: Capital cost for cooling towers is approximately $2.5 billion. System loses 860 megawatts capacity and annual operating and maintenance cost is increased by $13 million per year.
Probability of this scenario: 10 percent

Entrainment/Impingement Uncertainty

Scenario 1: Section 316(b) regulation, which applies to the effects of surface water intakes on aquatic biota, remains unchanged.
Impact on TVA: None
Probability of this scenario: 80 percent

Scenario 2: Section 316(b) regulations change in 1996 to require a reduction in entrainment/impingement effects at existing plants. TVA elects to comply by constructing cooling towers at existing thermal plants to reduce the volume of water taken into the plant. Towers in closed mode are added to all coal-fired plants, repairs are required at Sequoyah, and additional tower cells are required at Browns Ferry facilities.
Impact on TVA: Capital cost for cooling towers would be approximately $1.7 billion. Capacity is reduced by 860 megawatts, and operating and maintenance cost increases by $13 million per year.
Probability of this scenario: 20 percent

Toxics/Bioaccumulation Uncertainty

Scenario 1: No changes to regulations affecting surface water discharges.
Impact on TVA: None
Probability of this scenario: 75 percent

Scenario 2: Reauthorization of Clean Water Act in 2000 requires National Pollutant Discharge Elimination System permits for discharges of pollutants to groundwater which is "hydrologically connected to surface waters." TVA complies by lining all ash ponds at existing coal-fired plants. Ash in existing ash ponds is excavated and stabilized in lined areas. Metal cleaning waste ponds are lined.
Impact on TVA: Cost for existing plants will be $1.1 billion.
Probability of this scenario: 25 percent

Flow Alteration Uncertainty

Scenario 1: No new requirements (beyond TVA commitment to policy outlined in the Final Environmental Impact Statement, Tennessee River and Reservoir System Operation and Planning Review — Lake Improvement Plan).
Impact on TVA: None
Probability of this scenario: 80 percent

Scenario 2: States require additional minimum in-stream flows downstream of new and existing TVA hydro plants by 1998. Minimum in-stream flows would be maintained downstream of hydro plants by pumping water over the dam to the tailwater to supplement turbine releases.
Impact on TVA: Requires expenditure of $180 million capital and annual operating and maintenance cost increase of $11 million per year.
Probability of this scenario: 20 percent

Toxics/Bioaccumulation and pH Uncertainty

Scenario 1: No new regulation that is not covered under the Toxics/Bioaccumulation uncertainty above.
Impact on TVA: None
Probability of this scenario: 90 percent

Scenario 2: Reauthorization of Clean Water Act in 2005 requires the elimination of discharges of all pollutants by 2010. All surface water discharges, including thermal, and discharges to groundwater that are "hydrologically connected to surface water" would be eliminated. All thermal plants would operate closed cycle. Blow down and other miscellaneous wastewater are treated on-site, primarily by evaporation and constructed wetlands. All combustion byproducts and scrubber sludges are handled dry. Existing ash in ash ponds is stabilized in lined areas to eliminate discharge to groundwater. Chemical cleaning ponds are also to be lined.
Impact on TVA: Capital cost will be $11 billion and annual operating and maintenance costs increase by $14 million per year.
Probability of this scenario: 10 percent

EVALUATION CRITERIA

The Key to Criteria is a summary of the evaluation criteria that was used to evaluate each strategy. These criteria were crucial in the analysis of the strategies as shown in the various trade-off graphs. The units and a brief description of all key criteria are given in *Figure T8-38*.

FIGURE T8-38. **Key to Criteria**

Label	Description	Units
Customer Value Test	Customer Value Test	Present Value -(1996-2030)
Total Resource Costs	Total Resource Costs (TRC)	Present Value - (1996-2030)
Electric Market	Customer Value in Electric Market	Present Value - (1996-2030)
RIM Test	Rates Impact Measure (RIM) Test	$/MWh Levelized (1996-2030)
Short-Term Rates	Short-Term Rates	$/MWh Average from (1996-2000)
Mid-Term Rates	Mid-Term Rates	$/MWh Average from (1996-2005)
Long-Term Rates	Long-Term Rates	$/MWh Average from (1996-2015)
New Mid-Term Rates	Mid-Term Rates	$/MWh (2001-2005)
Debt 2001	Total Debt in Year 2001	Millions $
Debt 2007	Total Debt in Year 2007	Millions $
Total Employment	Total Employment Per Year	
Total Income	Average Annual	Thousands $
Environmental Criteria:		
CO Emissions	Carbon Monoxide (CO) Emissions	Annual Average Tons (1996-2030)
CO_2 Emissions	Carbon Dioxide (CO_2) Emissions	Annual Average Thousands of Tons (1996-2030)
NO_X Emissions	Nitrogen Oxides (NO_X) Emissions	Annual Average Tons (1996-2030)
SO_2 Emissions	Sulfur Dioxide (SO_2) Emissions	Annual Average Tons (1996-2030)
VOC Emissions	Volatile Organic Compounds (VOCs) Emissions	Annual Average Tons (1996-2030)
TSP Emissions	Total Suspended Particulates (TSPs) Emissions	Annual Average Tons (1996-2030)
Mercury Emissions	Mercury (Hg) Emissions	Annual Average Tons (1996-2030)
Solids	Solids	Annual Average Tons (1996-2030)
Thermal Discharge	Thermal Discharges	Annual Average Quadrillion BTUs (1996-2030)
Water Usage	Water Usage	Annual Average Trillions of Gallons (1996-2030)
Water Consumption	Water Consumption	Annual Average Trillions of Gallons (1996-2030)
Coal Burned	Coal Burned	Annual Average Millions of Tons (1996-2030)

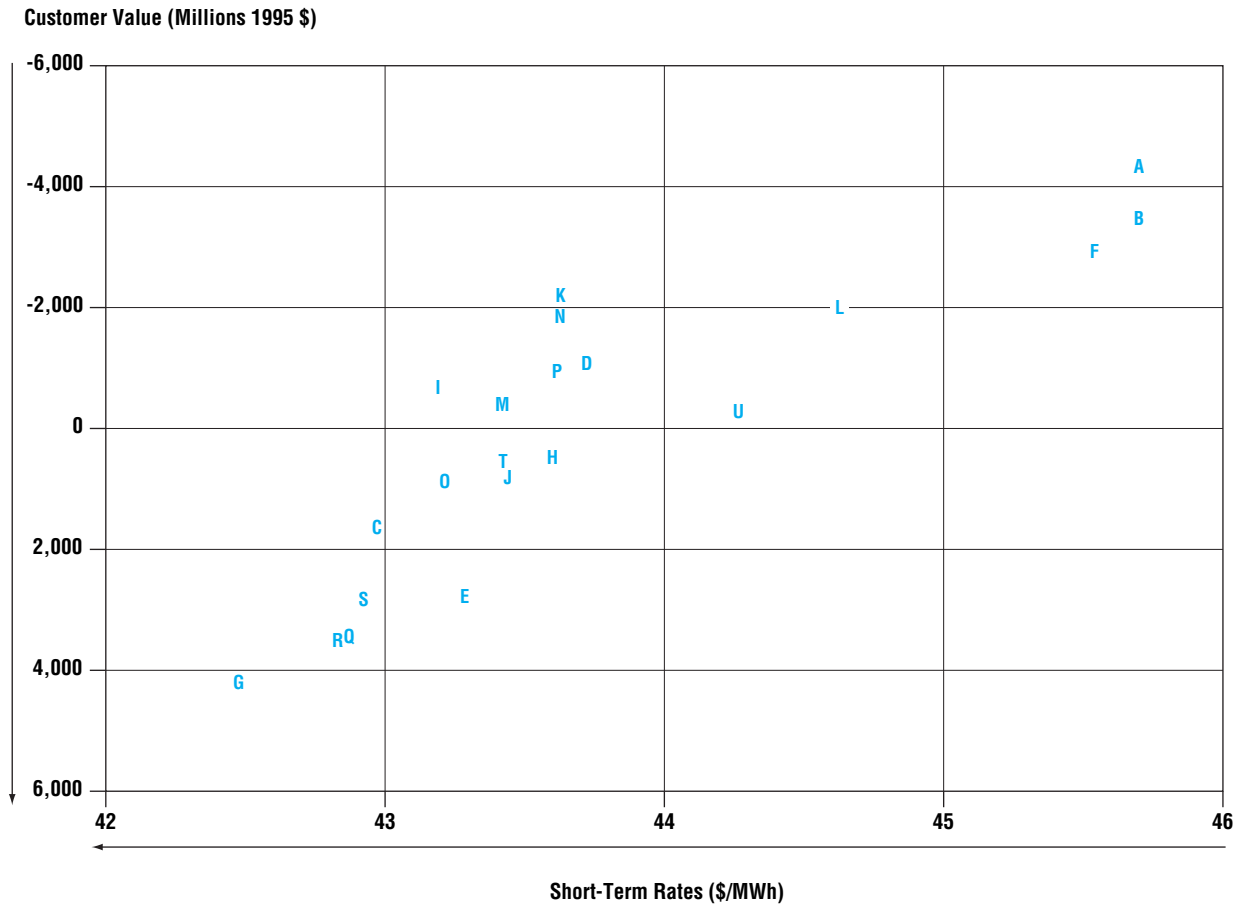
FIGURE T8-38. **Key To Criteria** *CONTINUED*

Label	Description	Units
Environmental Criteria:		
Biomass Burned	Biomass Burned	Annual Average Millions of Tons (1996-2030)
RDF Burned	Refuse-Derived Fuel (RDF) Burned	Annual Average Millions of Tons (1996-2030)
Landfill Methane Capture	Landfill Methane Capture	Annual Average Tons (1996-2030)
NG Burned	Natural Gas Burned	Millions of Standard Cubic Feet
Total Power Sales	Total Power Sales	MWh
Nuclear Power Sales	Nuclear Power Sales	MWh
Fossil Power Sales	Fossil Power Sales	MWh
Hydro Power Sales	Hydro Power Sales	MWh
Wind Capacity	Wind Capacity	MW
New Thermal Plants	New Thermal Plants	Number
Environmental Impacts:		
Air:		
Health - Inhalation	Human Health - Inhalation	Index
Visibility	Visibility	Index
Forests And Crops	Forests and Crops	Index
Materials	Materials (Structural and Cultural)	Index
Water:		
Health - Ingestion	Human Health - Ingestion	Index
Water Supply/ Assimilation	Water Supply/Waste Assimilation	Index
Aquatic/Biodiversity	Fish and Aquatic Life/ Biodiversity	Index
Other:		
Greenhouse Gases	Greenhouse Gas Emissions	Total Equivalent Carbon Dioxide (Millions of Tons)

TRADE-OFF GRAPHS

The Trade-off Graphs represent how each strategy performs given certain criteria. Specifying a particular future, some strategies were better than others for each criteria. To illustrate the evaluation of certain strategies, as well as the correlation of some of the criteria, three sets of trade-off graphs focusing on specific criteria are attached. They are cost, rates, debt, and value trade-offs, *Figures T8-39* through *T8-41*; environmental emissions trade-offs, *Figures T8-42* through *T8-48*; and environmental impacts

FIGURE T8-39. **Costs, Rates, Debt, and Value Trade-Off**
Customer Value vs. Short-Term Rates



Strategy

- **A** Minimum Carbon Dioxide—Natural Gas Repowering of Existing Coal
- **B** Minimum Carbon Dioxide—Natural Gas Repowering of Existing Coal and Renewables
- **C** Low-Cost Producer (Coal-Based)
- **D** Combined Cycle, Purchased Power, Coal (Reference)
- **E** Maximum Customer Value Index—Off-System Sales, High Beneficial Electrification, Declining Block Pricing
- **F** Low Total Resource Cost, High Demand-Side Management
- **G** Maximum Sales
- **H** Maximum Capacity Diversity
- **I** Bellefonte Nuclear Partnership
- **J** Bellefonte Coproduct, Renewables, Independent Power Producers
- **K** Defer and Build Browns Ferry 1 and Watts Bar 2 with Reference Expansion
- **L** Minimum Carbon Dioxide with Less Demand-Side Management
- **M** Combined Demand-Side Management and Off-System Sales
- **N** Decentralized Generation with More Renewables
- **O** Bellefonte Coproduct, More Demand-Side Management, More Off-System Sales
- **P** Low-Cost Renewables, Low-Price Demand-Side Management, Repowering
- **Q** Flexible with External Options
- **R** Flexible with Internal Options
- **S** Low Cost, Low Rates, Improved Environment
- **T** Low-Cost Renewables, Low-Price Demand-Side Management, Repowering, Bellefonte Coproduct Partnership
- **U** Low-Cost Renewables, More Demand-Side Management, Repowering, Bellefonte Coproduct Partnership

trade-offs, *Figures T8-49* through *T8-55*. In the environmental emissions trade-offs, there is a correlation between the emission criteria. In the environmental impacts trade-offs, there is a correlation between the environmental air impact indices. As the air quality becomes better, the attributes associated with the environmental air impacts also improve. There is no true correlation between the environmental water impact indices *(Figures T8-53* through *T8-55)*.

FIGURE T8-40. **Costs, Rates, Debt, and Value Trade-Off**
Short-Term Rates vs. Total Resource Costs

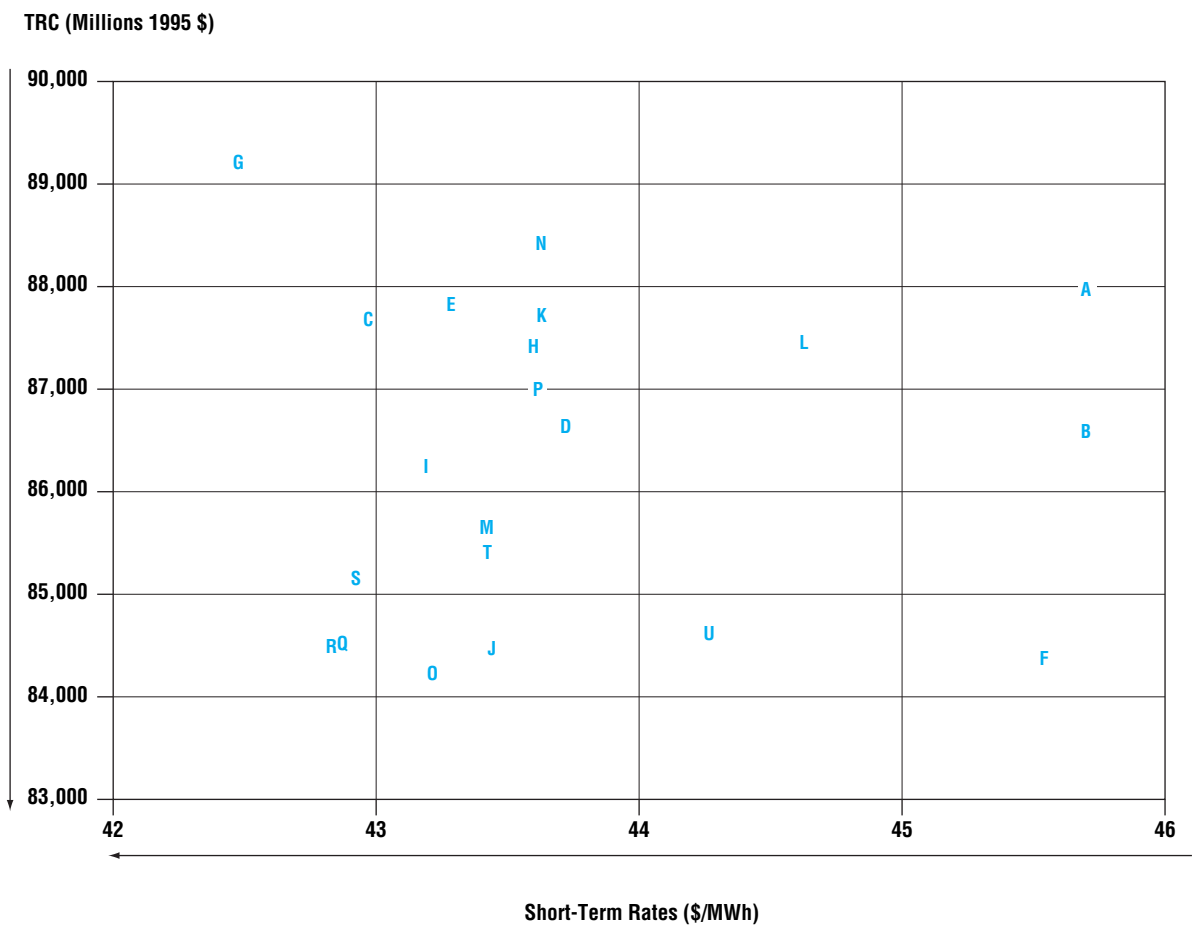


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FIGURE T8-41. **Costs, Rates, Debt, and Value Trade-Off**
Debt in Year 2001 vs. Total Resource Costs

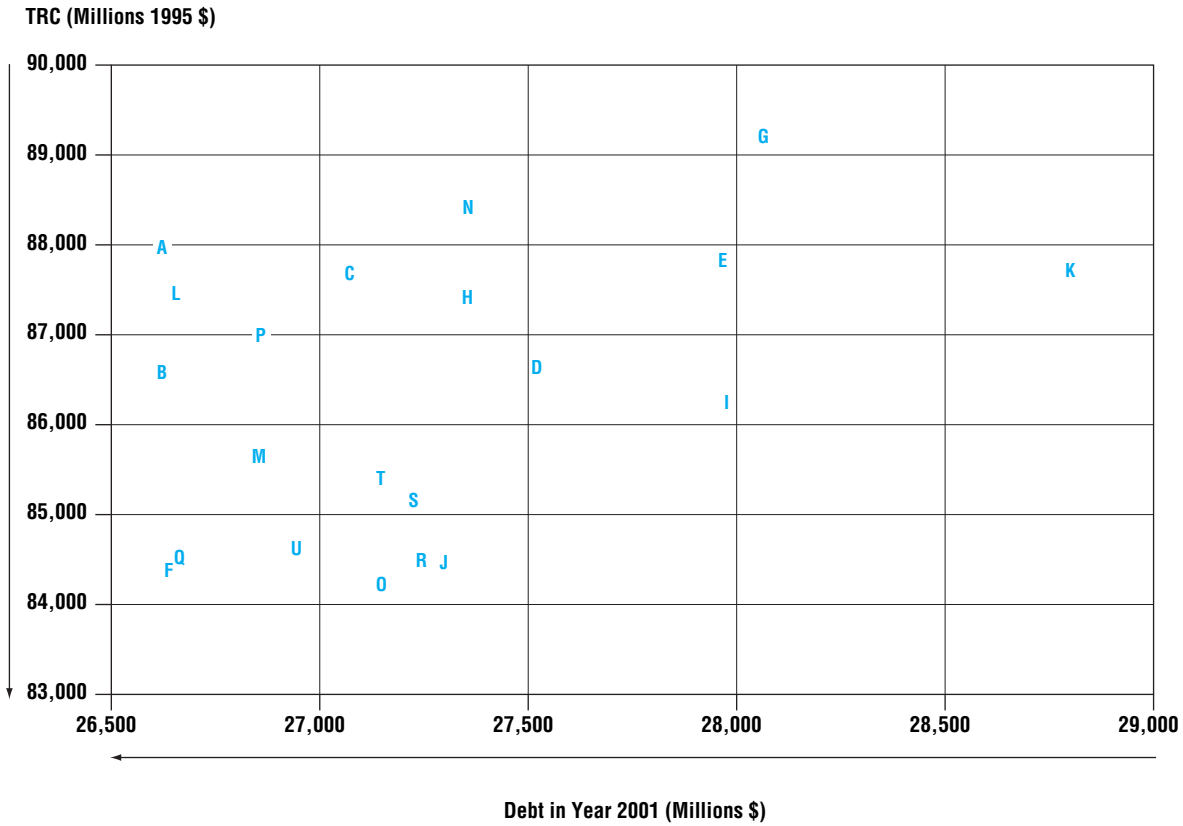

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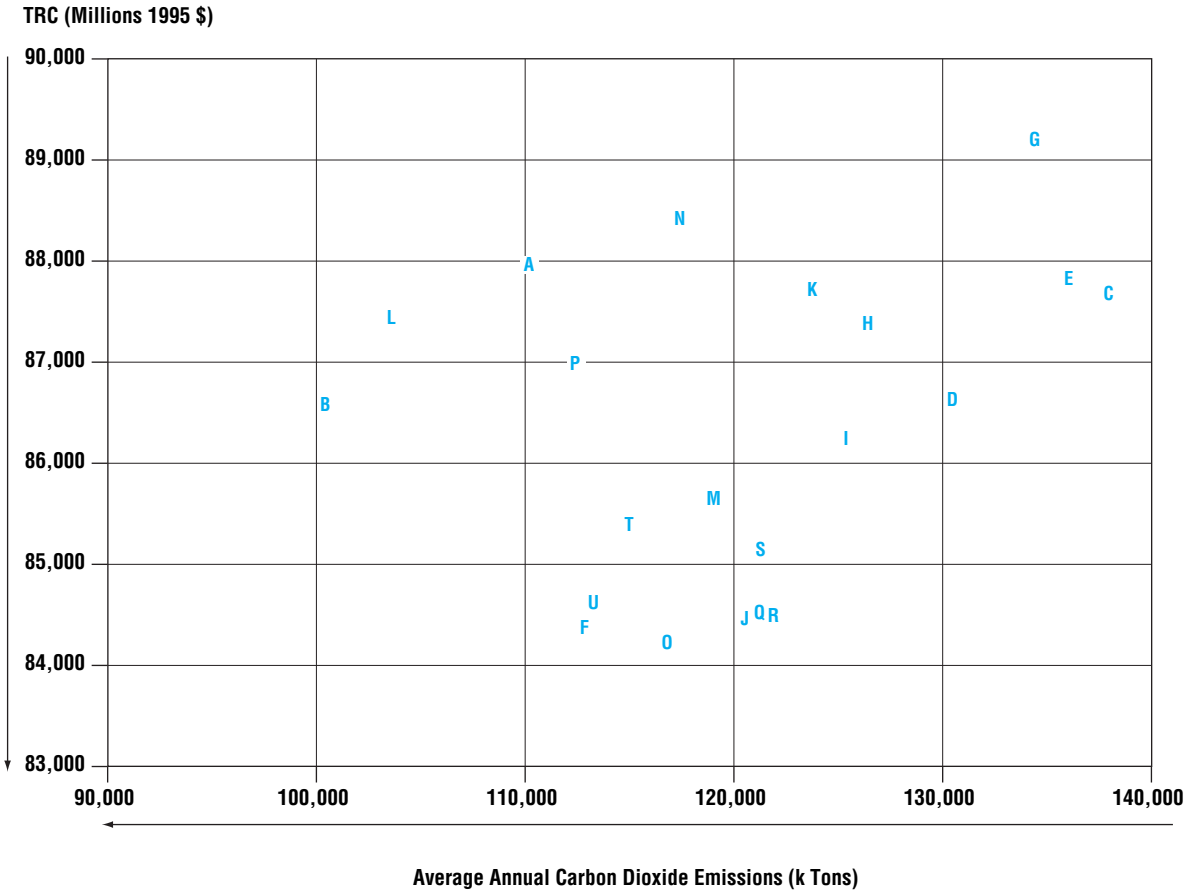
FIGURE T8-42. Environmental Emissions Trade-Off
Average Annual Carbon Dioxide Emissions vs. Total Resource Costs



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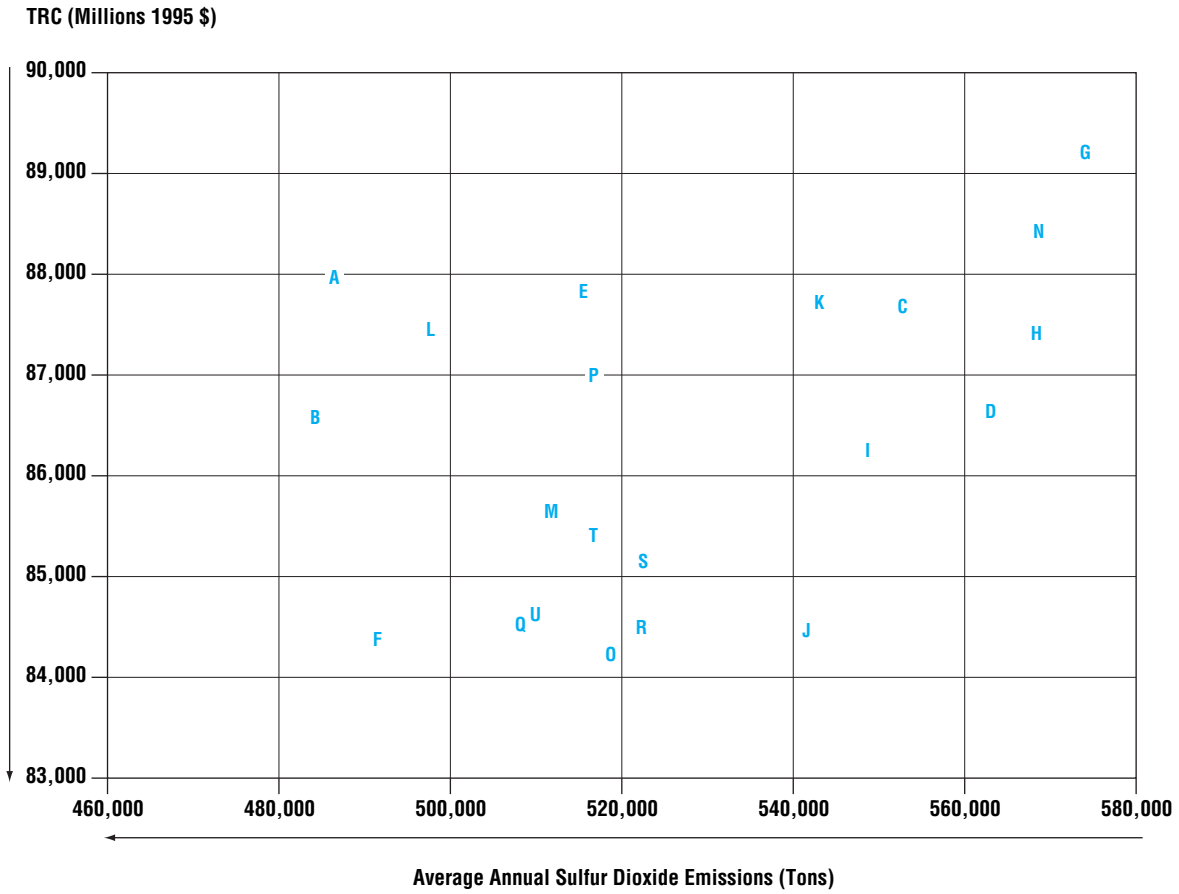
- **U** Low-Cost Renewables, More Demand-Side Management, Repowering, Bellefonte Coproduct Partnership

FIGURE T8-43. Environmental Emissions Trade-Off
Average Annual Sulfur Dioxide Emissions vs. Total Resource Costs



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- **J** Bellefonte Coproduct, Renewables, Independent Power Producers
- **K** Defer and Build Browns Ferry 1 and Watts Bar 2 with Reference Expansion
- **L** Minimum Carbon Dioxide with Less Demand-Side Management
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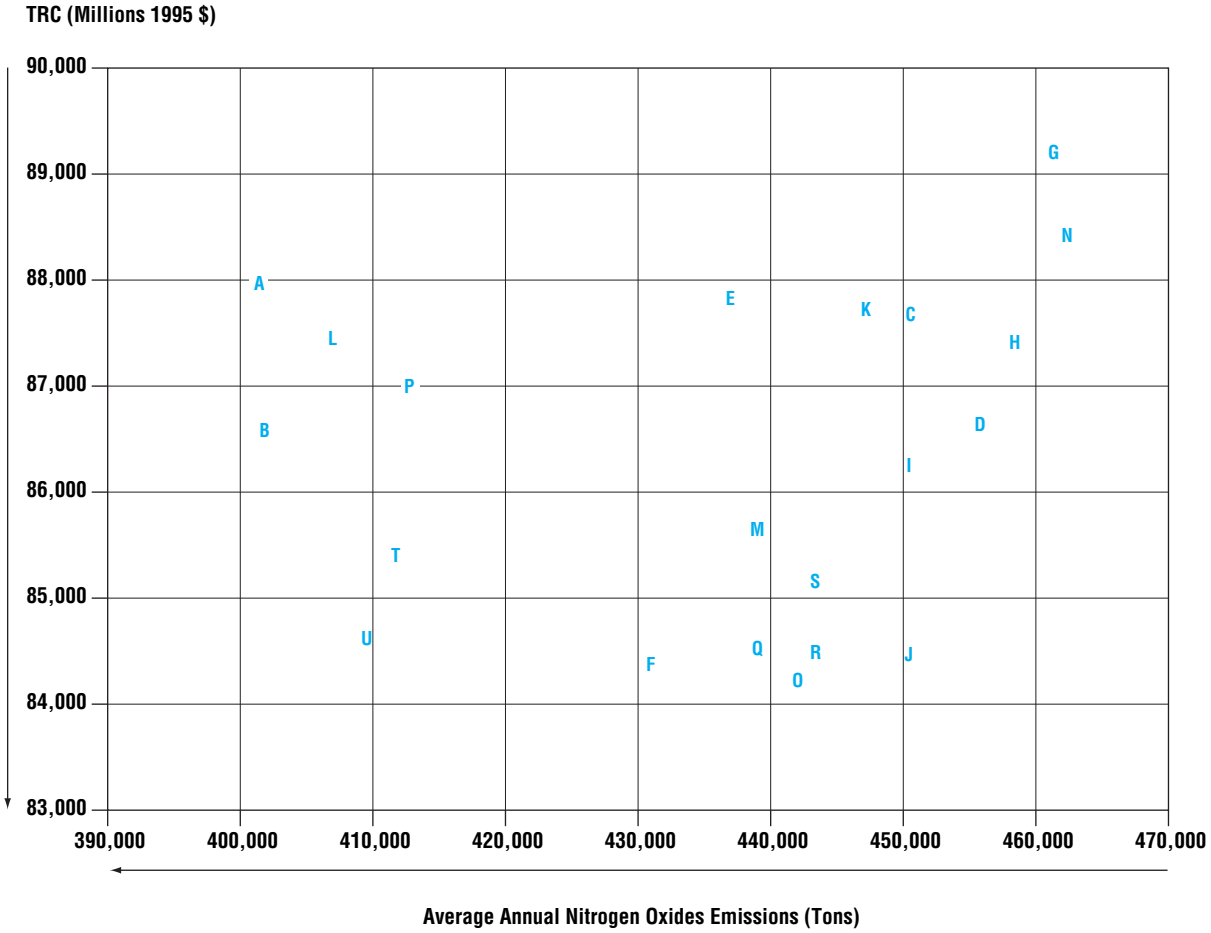
- **U** Low-Cost Renewables, More Demand-Side Management, Repowering, Bellefonte Coproduct Partnership

FIGURE T8-44. **Environmental Emissions Trade-Off**
Average Annual Nitrogen Oxides Emissions vs. Total Resource Costs



Strategy

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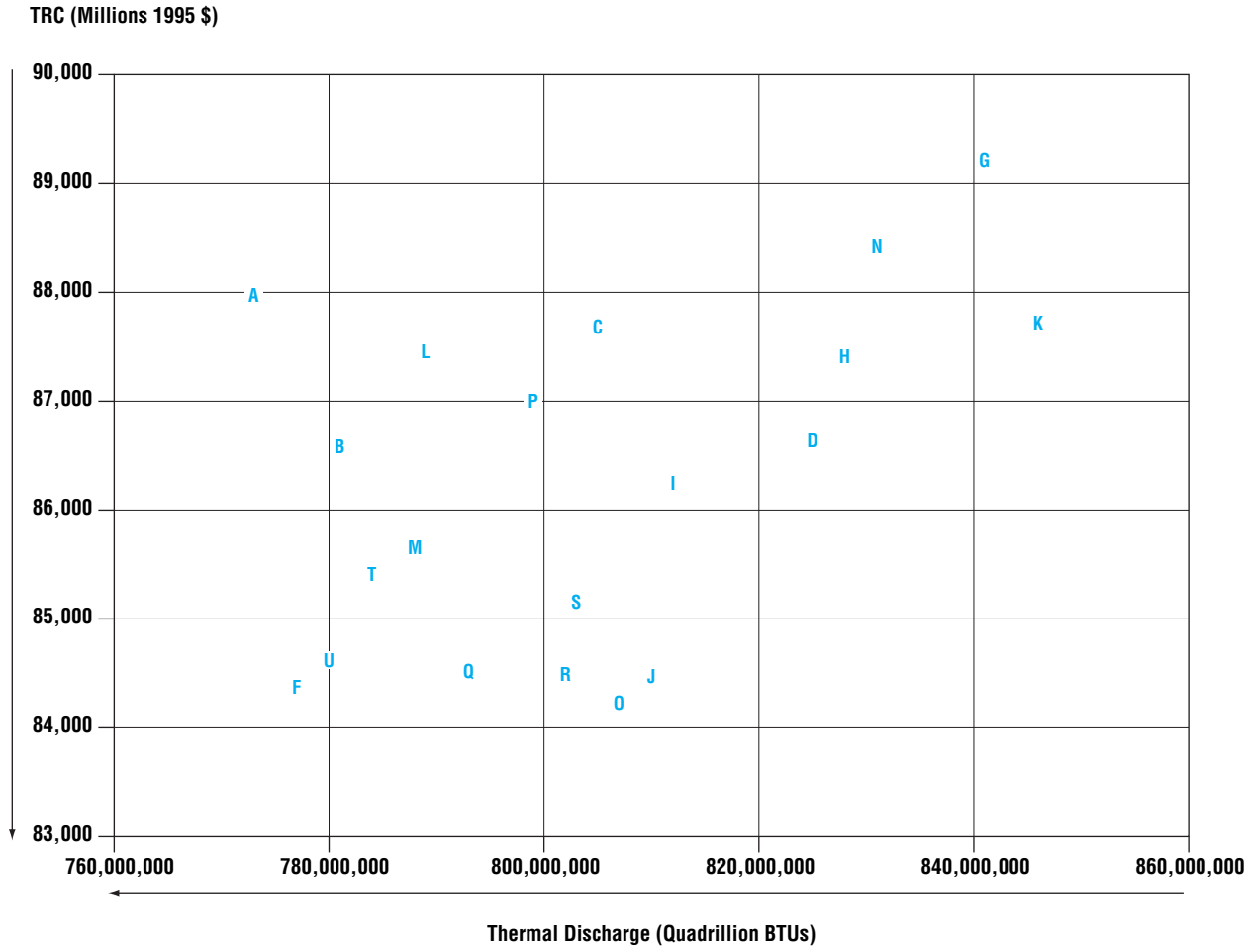
- **U** Low-Cost Renewables, More Demand-Side Management, Repowering, Bellefonte Coproduct Partnership

FIGURE T8-45. **Environmental Emissions Trade-Off**
Thermal Discharge vs. Total Resource Costs



Strategy

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FIGURE T8-46. **Environmental Emissions Trade-Off**
Volatile Organic Compounds vs. Average Annual Carbon Dioxide Emissions

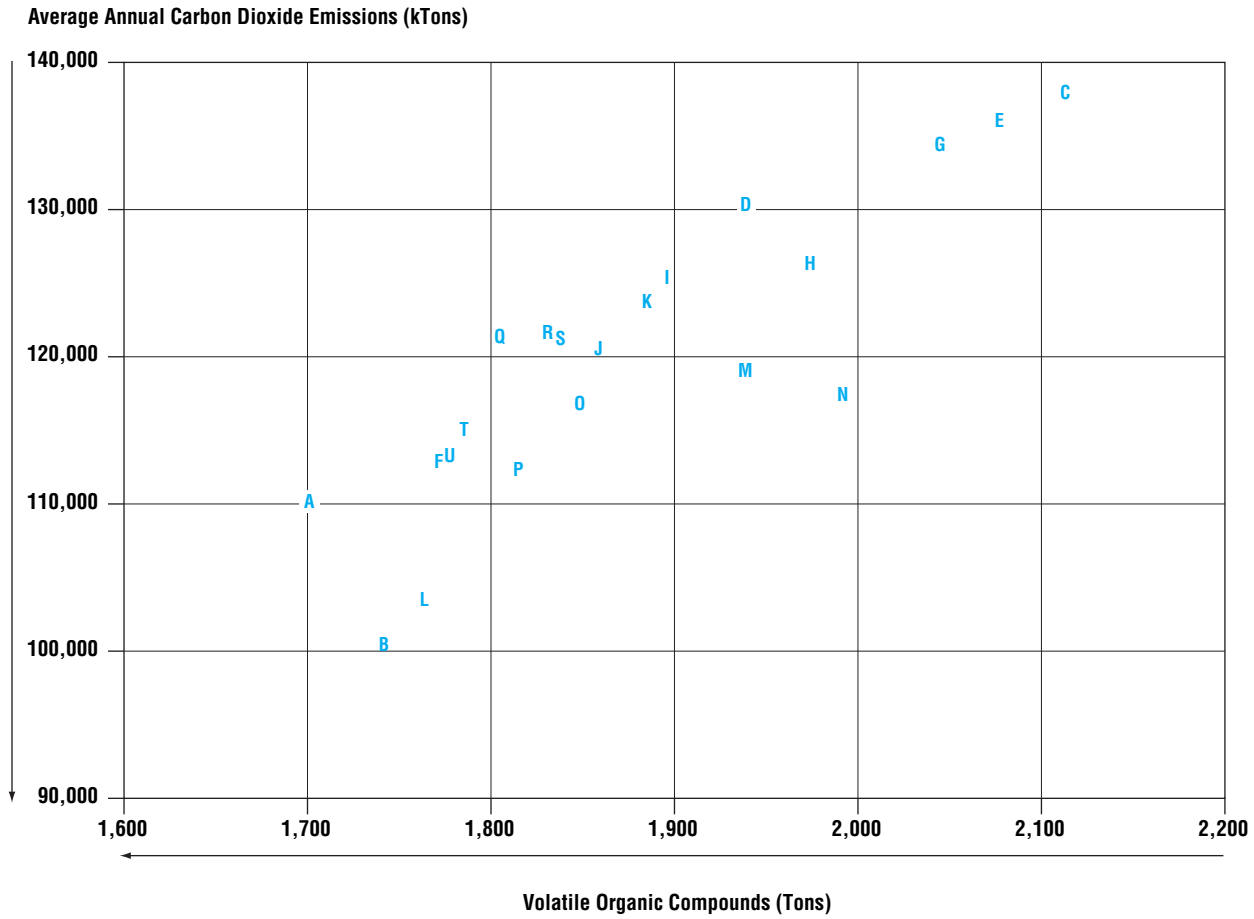

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FIGURE T8-47. **Environmental Emissions Trade-Off**
Total Suspended Particulates vs. Average Annual Carbon Dioxide Emissions

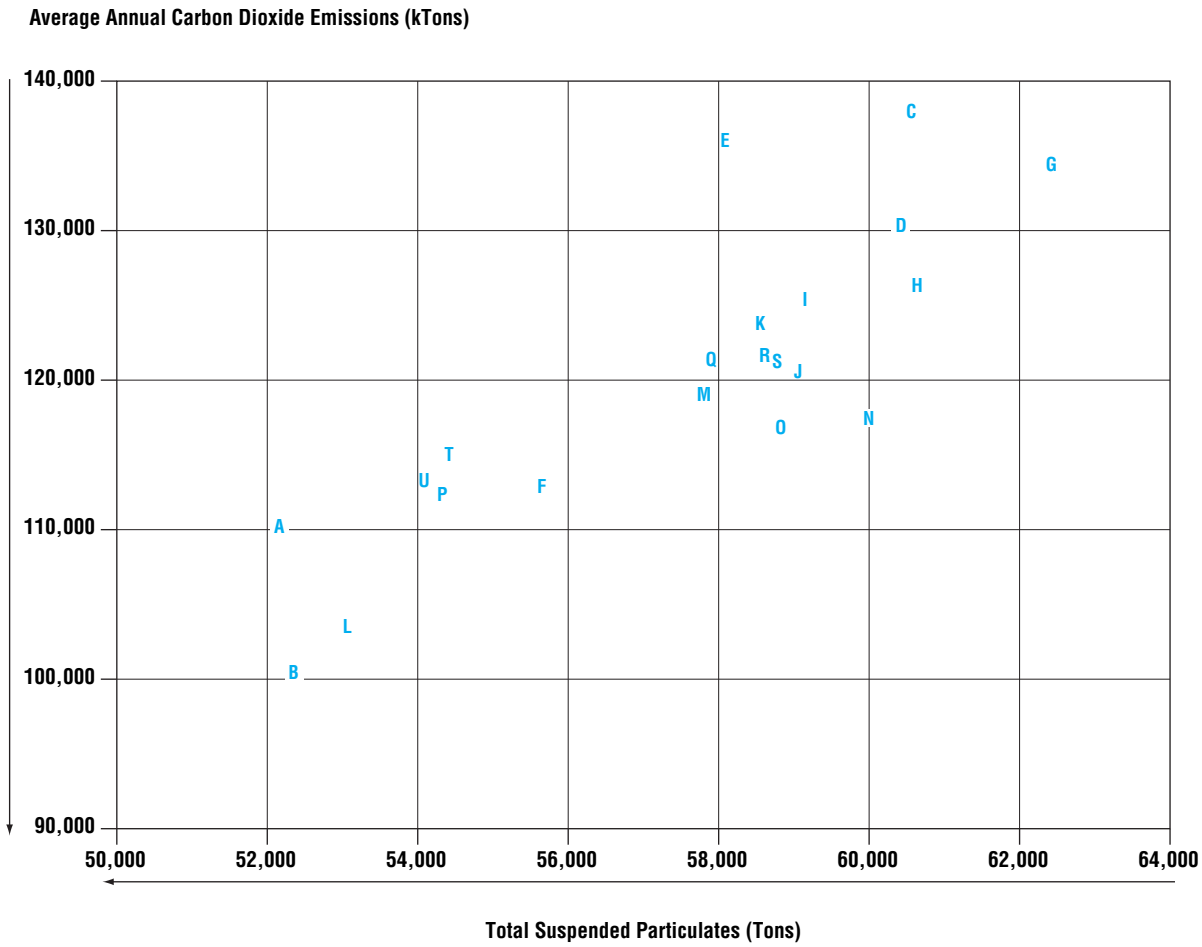

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FIGURE T8-48. Environmental Emissions Trade-Off Thermal Discharge vs. Average Annual Carbon Dioxide Emissions

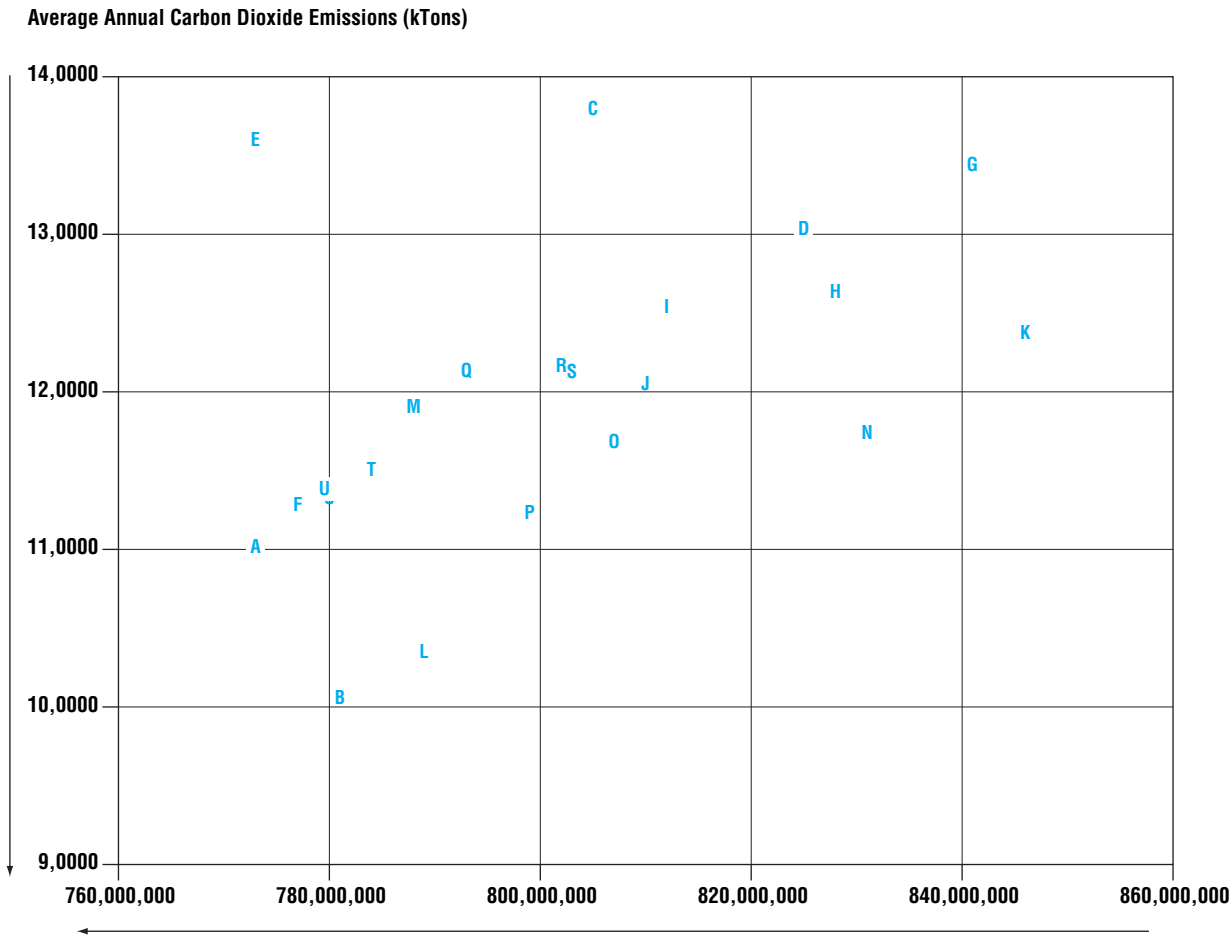

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FIGURE T8-49. **Environmental Impacts Trade-Off**
Greenhouse Gases vs. Health Inhalation

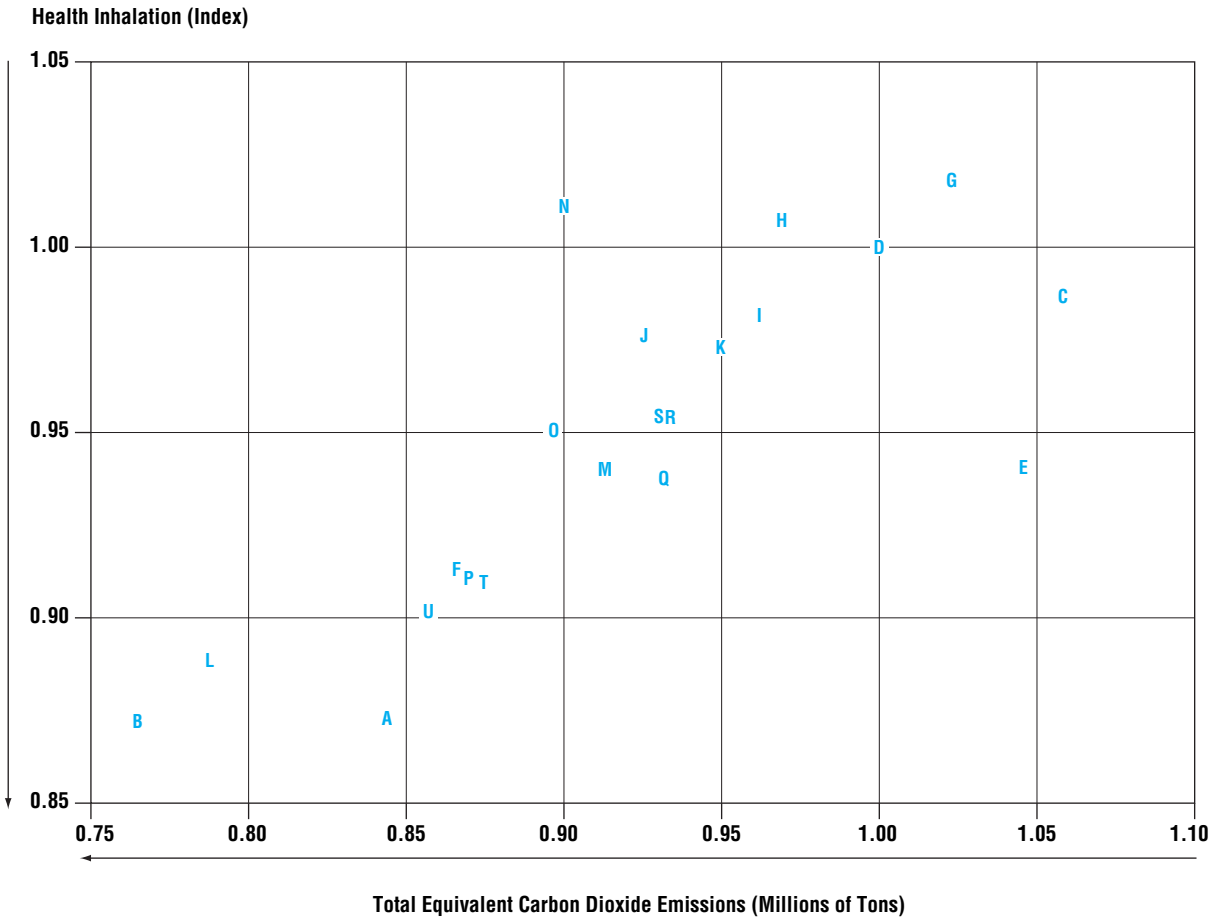

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FIGURE T8-50. **Environmental Impacts Trade-Off**
Visibility Impairment vs. Health Inhalation

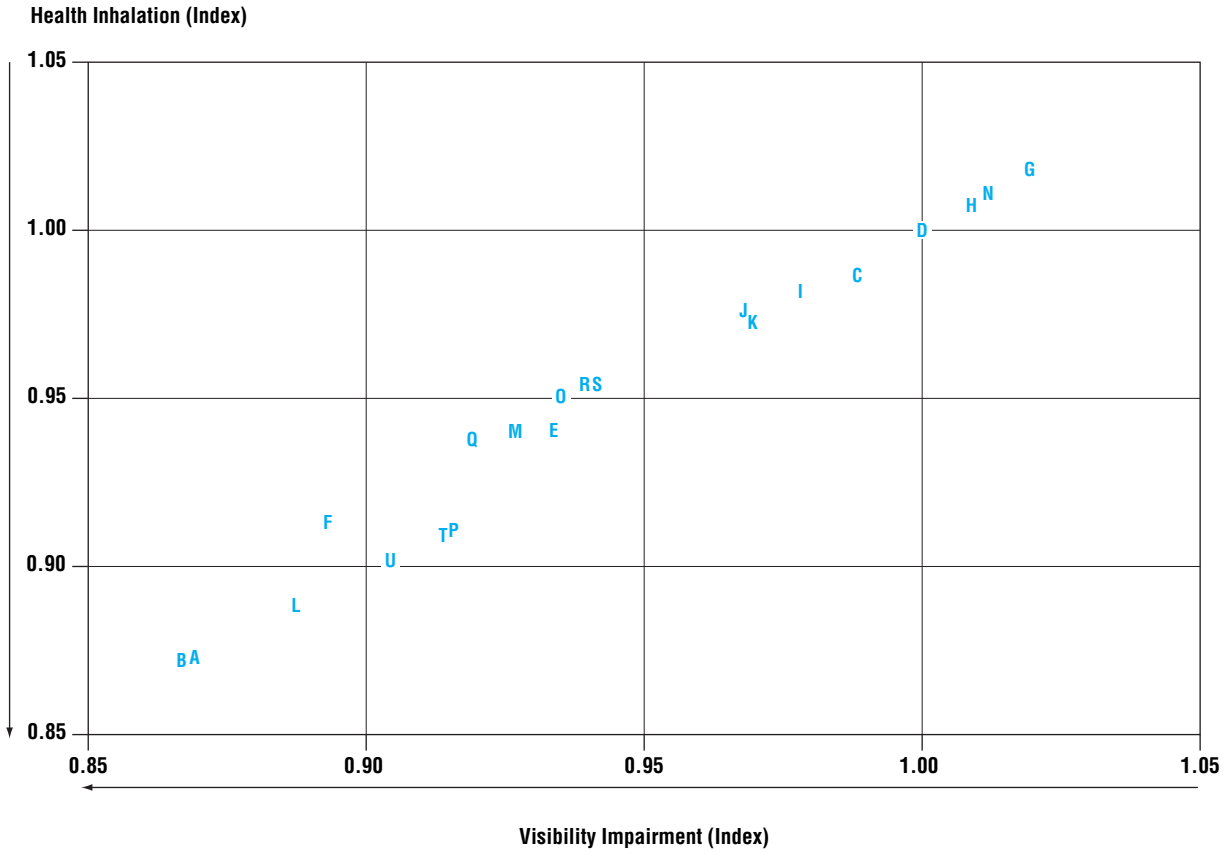

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FIGURE T8-51. **Environmental Impacts Trade-Off**
Forests & Crops vs. Health Inhalation

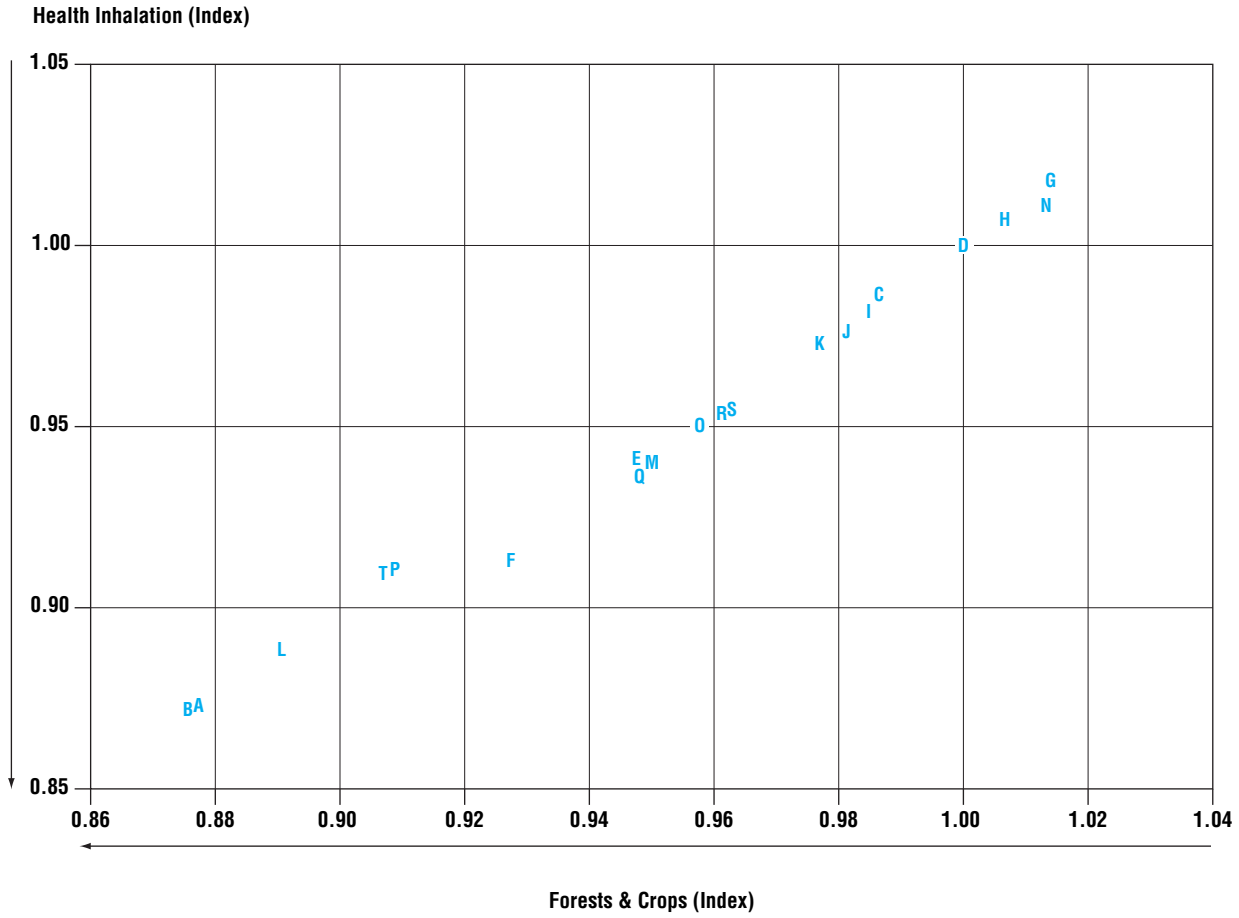

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FIGURE T8-52. **Environmental Impacts Trade-Off Materials vs. Health Inhalation**

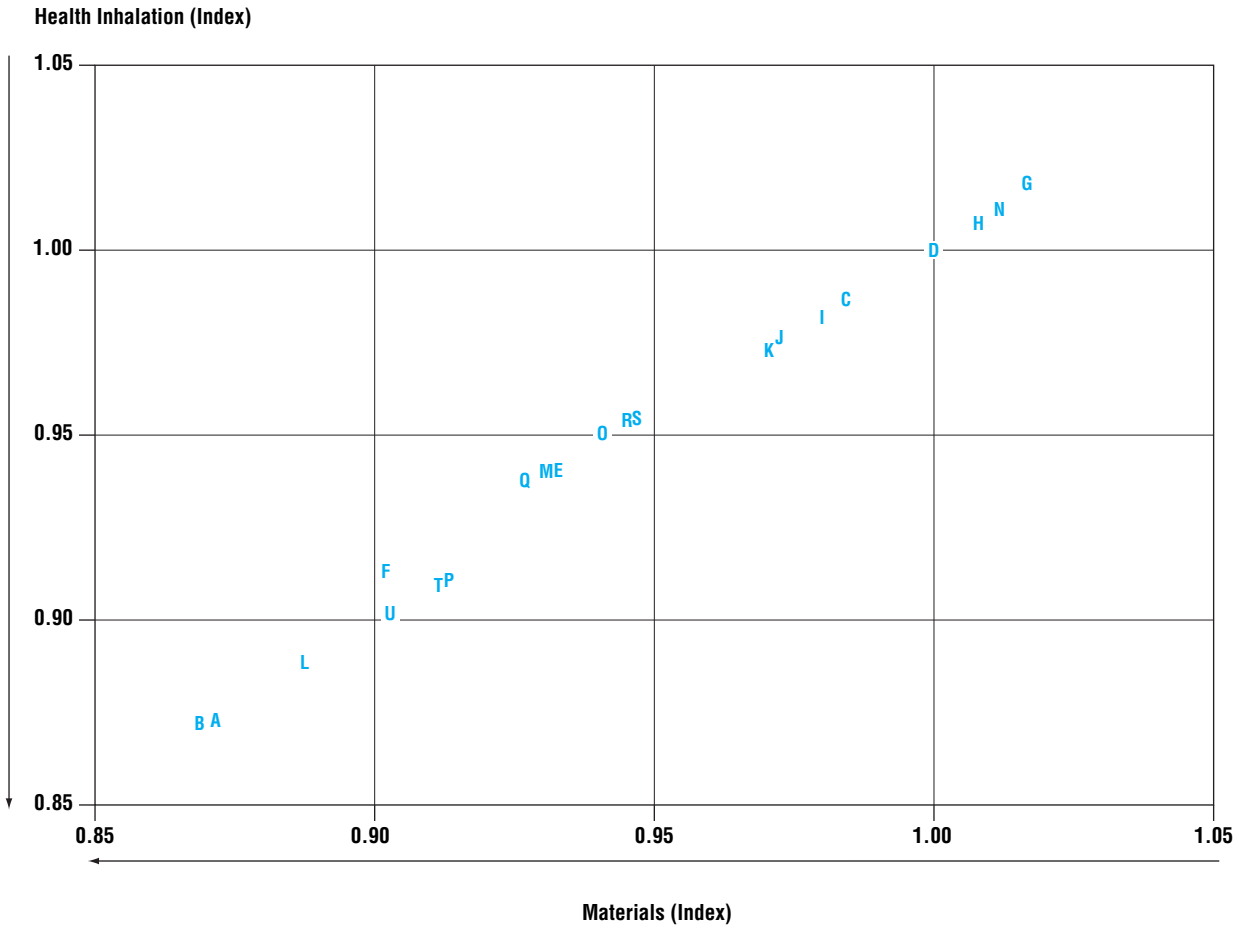

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FIGURE T8-53. **Environmental Impacts Trade-Off**
Water Supply & Waste Assimilation vs. Health Ingestion

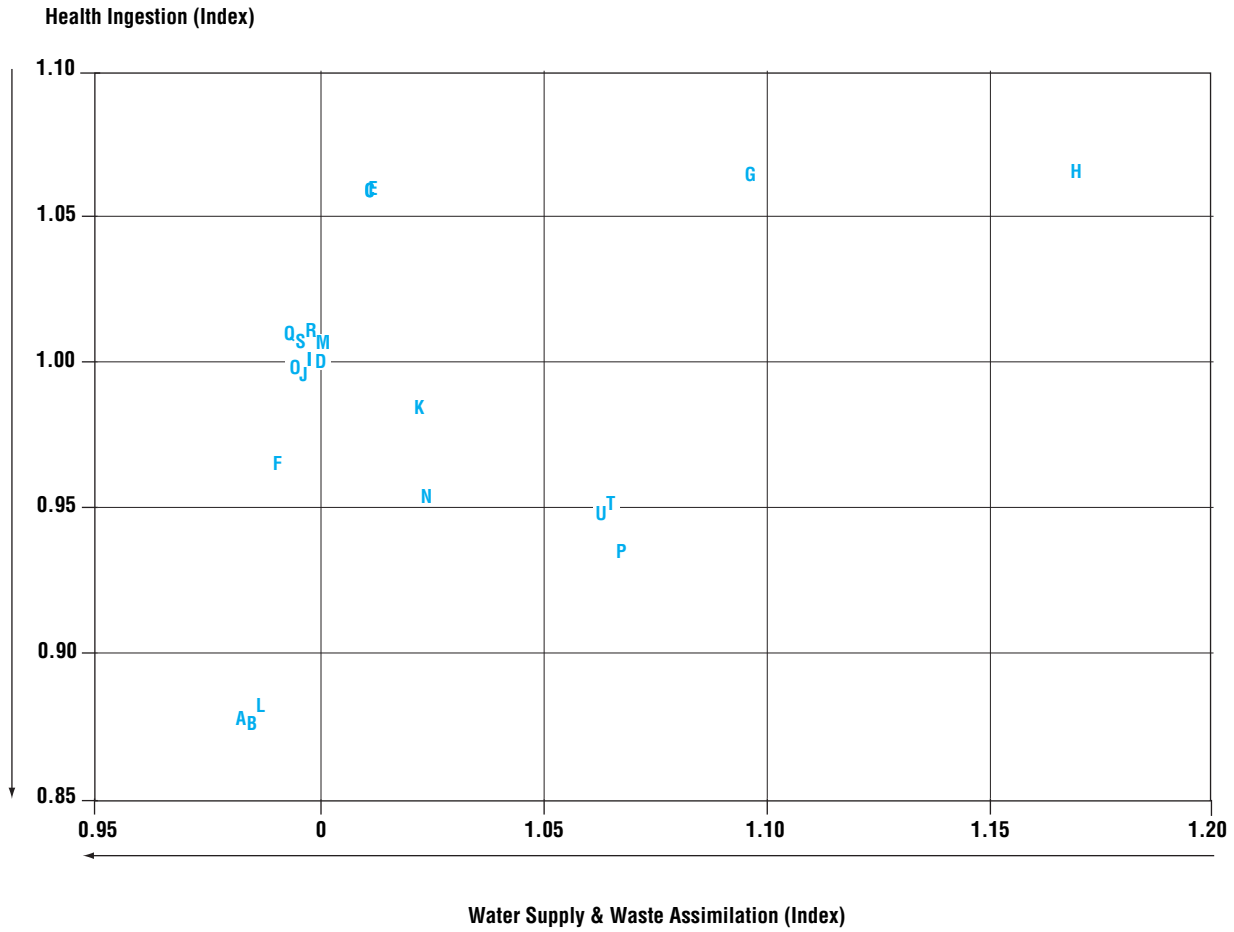

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FIGURE T8-54. **Environmental Impacts Trade-Off**
Fish & Aquatic Life vs. Health Ingestion

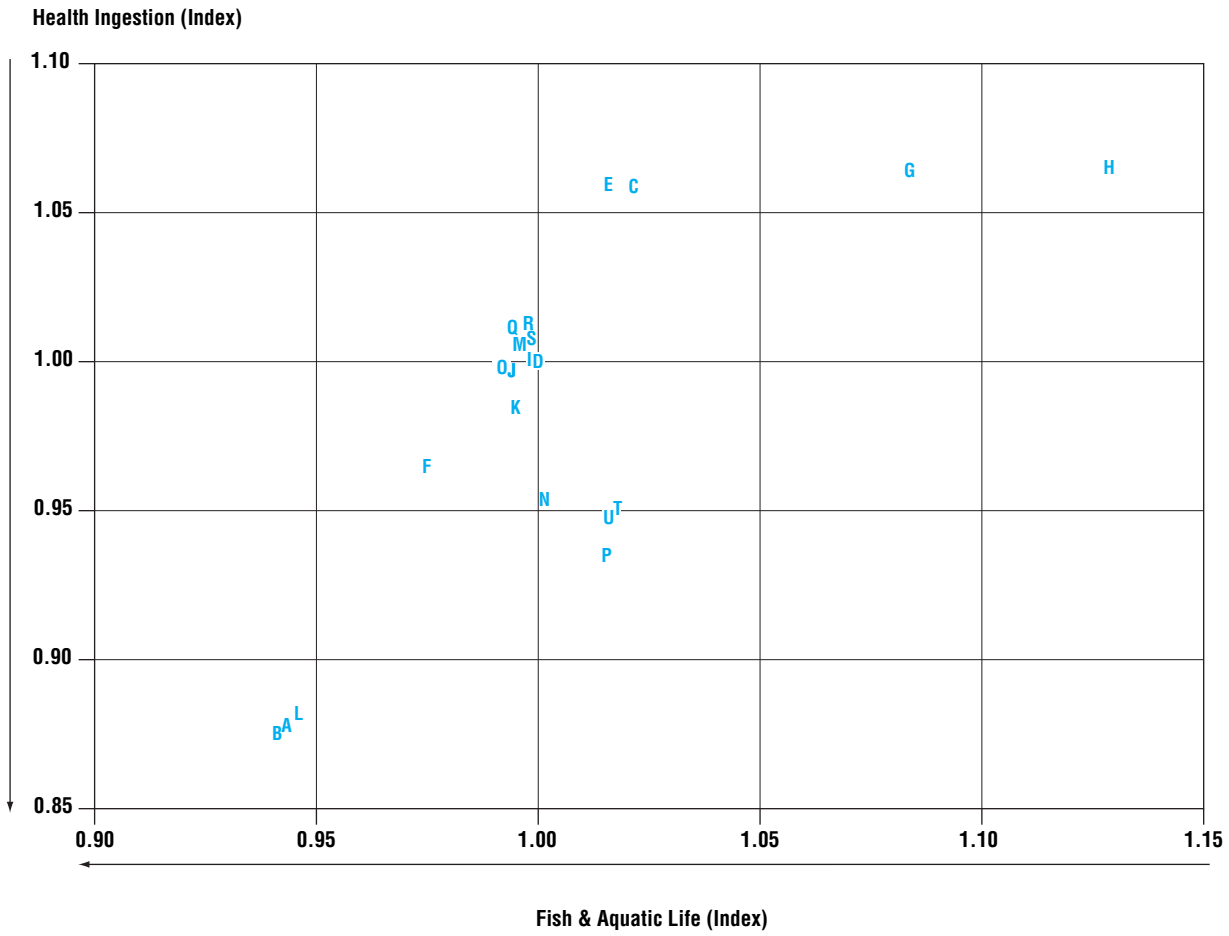

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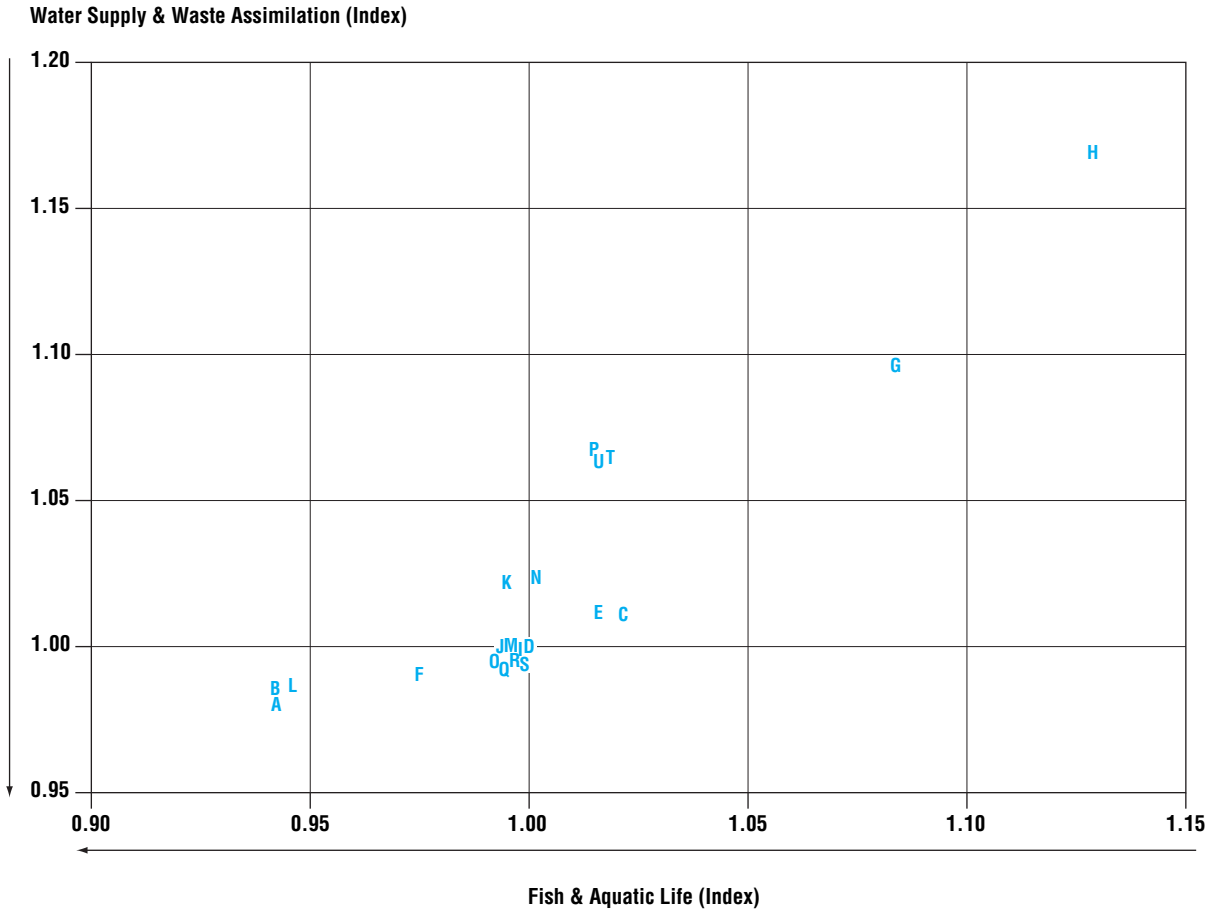
FIGURE T8-55. **Environmental Impacts Trade-Off**
Fish & Aquatic Life vs. Water Supply & Waste Assimilation



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TVA'S NUCLEAR OPTIONS

This paper is from a report, "TVA's Nuclear Options, A Report on Bellefonte Units 1 and 2, Watts Bar Unit 2, and Browns Ferry Unit 1," that was issued by TVA in December 1994.

Overview

This is an interim review of issues involving four unfinished or inoperative TVA nuclear units and their impacts on rates, debt, long-term costs and flexibility for meeting future power needs. It has been developed largely in response to concerns identified through TVA's Integrated Resource Planning (IRP) process.

The three major concerns identified in TVA's IRP to date—debt, competitiveness, and nuclear power—are interrelated. In the opinion of many TVA customers and the public, high debt is generally associated with a poor competitive position. Since the large capital expenditures necessary to complete TVA's nuclear units will increase TVA's debt, completing these units contributes to a perception that TVA's competitiveness will suffer. With this in mind, the TVA Board of Directors requested the Chief Financial Officer (CFO) to initiate a study to look at the possibility of stopping the growth of debt. A summary of the conclusion of this study is:

> "The results of this review, which has encompassed the involvement of all areas of the TVA, is that TVA can limit its level of debt to $2 billion to $3 billion below the $30 billion debt ceiling and can achieve this limitation by the end of fiscal year 1997."

Additionally, the Board of Directors is requesting that the Chief Financial Officer conduct a feasibility study of reducing future levels of debt. The internal limit on debt would be formally reviewed periodically to ensure that this limitation meets TVA's continuing business needs. The debt limit will be carefully observed in the development of TVA's Integrated Resource Plan. The IRP will examine the disposition of TVA's debt in light of an increasingly competitive business environment.

TVA has three nuclear units in various stages of construction with scheduled completion dates ranging from 2003 to 2006. These units and current estimates of the costs to complete them are:

- Bellefonte Units 1 and 2, near Hollywood, Alabama—$4.4 billion
- Watts Bar Unit 2, near Spring City, Tennessee—$2.2 billion
- In addition, one TVA nuclear unit previously licensed to operate would need major modifications and is tentatively scheduled to return to service in the year 2001:
- Browns Ferry Unit 1, near Decatur, Alabama—$2.4 billion

The question of how to proceed with these four nuclear units is of critical importance to TVA and the region it serves. The total cost to complete or restore them to service as nuclear units is estimated to be about $9 billion—unquestionably a major investment by TVA customers. But in addition to these costs, TVA must consider several other factors, such as:

- The need for power in the future
- The cost of other options that could replace the nuclear units
- Prior investment in the nuclear units
- TVA's long-term costs
- TVA's rising debt
- The impact of any decision on short- and long-term rates
- The environmental effects of various options

All of these issues are currently being addressed in TVA's IRP, a comprehensive study of future power needs in the TVA region and the various ways and costs of meeting them. The IRP will not be completed until late 1995. However, several concerns regarding TVA's nuclear construction plans have already been identified through the IRP process. It is necessary, therefore, to review the current status of these units to ensure that they are being managed in the most cost-effective and beneficial manner for TVA customers.

As a result of this review, staff recommends that over the near term TVA should not fund the completion or restoration of Bellefonte Units 1 and 2, Watts Bar Unit 2, and Browns Ferry Unit 1 as nuclear units. Instead, TVA should keep open alternatives for these units that would minimize short-term rates, increase long-term flexibility, minimize long-term costs, and limit debt.

Alternatives to completing/restoring these units as nuclear units include:

- Converting them to another technology such as natural gas
- Replacing them with different types of supply- and demand-side resource options
- Completing the construction of one or more units in partnership with others

- Maintaining the nuclear units in a "mothballed" state and deciding later whether to complete or replace them

Some options could involve limited TVA investment in the future. All options will be carefully considered in the IRP process and, ultimately, the most cost-effective long-term uses for these units will be decided by the TVA Board of Directors.

Introduction

TVA formally began its IRP process in February 1994. An IRP is a process for identifying, thoroughly evaluating, and selecting a set of resource options to meet the expected future consumer demand for electricity. TVA's IRP process is called "Energy Vision 2020."

TVA is committed to developing an energy strategy for the future with considerable input from customers and stakeholders. Decisions and recommendations for meeting future energy needs will take into account the values and expectations customers have for their energy supplier for both electrical generation and demand-side options, as well as for new energy technologies. Information TVA receives from stakeholders is being incorporated into the technical analysis process for Energy Vision 2020.

A series of open meetings provided an opportunity for TVA to both inform the public about its resource planning process and collect valuable input from the public. From July to November, TVA held 12 meetings throughout the Tennessee Valley. Approximately 300 people attended to view the Energy Vision 2020 displays, talk with TVA representatives, and provide input to the planning process. After publication of the draft IRP in July 1995, there will be another round of public meetings across the Valley. These meetings will update the public on the latest findings and provide an opportunity to review and react to TVA's draft plan.

During the summer of 1994, one-on-one interviews were conducted with about 100 opinion leaders across the Tennessee Valley and in Washington, DC. The opinion leaders represented distributors of TVA power, industrial customers, environmental advocates, government, and community leaders. A questionnaire was designed to gather opinions on the issues TVA will examine in Energy Vision 2020. The questions fell into three major areas:

- General questions about the Tennessee Valley region
- Questions about economic development and the environment
- TVA-specific questions

The Energy Vision 2020 Review Group was established in June 1994 to bring key stakeholders into TVA's energy planning process. It consists of 18 representatives from various organizations outside TVA with a wide variety of views and interests. Members of the group provide input and views on TVA's planning assumptions, new options for consideration, and issues associated with long-term energy planning. To date, the Review Group has had seven intensive, full-day sessions, performing in-depth reviews of TVA's IRP planning assumptions and the overall IRP process. Four additional meetings are scheduled.

The Tennessee Valley Public Power Association, an association of the 160 distributors of TVA power, has established a Power Supply Planning Committee. This 28-member committee provides critical reviews of TVA's IRP process and of the major issues facing TVA and the distributors. Since it was formed in May 1994, TVA has met with the committee three times to discuss energy planning issues affecting TVA's wholesale customers.

Through this interactive public participation process and internal reviews, numerous concerns have been identified. Among those most frequently voiced are:

1. TVA's competitive position
2. TVA's nuclear program
3. TVA's debt

With many of the fundamental assumptions necessary for an energy strategy already in an advanced state of review in the IRP process, TVA staff has been able to perform a preliminary analysis of these three concerns. As a result, the staff has prepared this interim report to present the latest findings to the TVA Board of Directors. It should be stressed that these are only initial findings. Taking interim action on these findings would not pre-empt the ultimate decisions to be made through the IRP process. Rather, this will enhance TVA's ability to respond to the rapidly developing competitive environment of the electric utility industry.

This report examines the question of whether TVA should fund the completion or restoration of Bellefonte Units 1 and 2, Watts Bar Unit 2, and Browns Ferry Unit 1 as nuclear units. Alternatives to TVA completing these units include:

- Converting them to another technology such as natural gas
- Replacing them with different types of supply- and demand-side resource options
- Completing the construction of one or more of the units in partnership with others
- Maintaining the nuclear units in a "mothballed" state and deciding later whether to complete or replace them

A more detailed explanation of these alternatives is described in the Nuclear Options Appendix.

Each of these alternatives will affect future costs, electric rates, debt, and environmental impacts, as well as TVA's ability to respond to an ever-changing marketplace. In this paper, we will:

- Review certain key assumptions, such as the need for power,

FIGURE T8-56. **Residential Costs – CalendarYear 1993**

Kentucky Utilities	4.4 ¢/kWh
Kentucky Power	4.9
Kingsport Power	5.1
Appalachian Power (VA)	5.7
Public Service of Indiana	5.8
TVA	**5.9**
Louisville Gas & Electric	6.0
Mississippi Power	6.2
Ohio Power	6.3
East Kentucky Power	6.4 [1]
Gulf Power	6.6
Big Rivers	6.9
South Carolina Elec & Gas	7.1
Alabama Power	7.2
Duke Power	7.3
Union Electric	7.5
Georgia Power	7.8
Louisiana P&L	7.8
Florida Power	7.9
New Orleans Pub Ser	7.9
Florida P&L	8.1
Gulf States Utilities	8.2
Carolina P&L	8.3
Virginia Power	8.6
Mississippi P&L	8.6
Arkansas P&L	9.3
Illinois Power	10.2

[1] Using South Kentucky REC Corp. as representative of East Kentucky Power Coop

Source: DOE 826, REA Forms 7 & 12, and TVA Electric Sales Statistics

cost of the nuclear units, and several other key assumptions that significantly affect the alternative choices available concerning the TVA nuclear construction program.

- Evaluate the changes in costs, electric rates, and debt resulting from the different resource choices.
- Draw some preliminary conclusions upon which the TVA Board may wish to act.

TVA'S COMPETITIVE POSITION

TVA electric rates are currently competitive with other utilities. Comparisons of TVA rates with surrounding utilities for residential, commercial, and industrial customers are shown in *Figures T8-56*, *T8-57*, and *T8-58*.

TVA's residential electric rates are lower than most surrounding utilities. Of the 27 Southeastern utilities shown in *Figure T8-56*, TVA ranks sixth lowest. Likewise, TVA's commercial and industrial rates are below the median level of other utility rates shown in *Figures T8-57* and *T8-58*. The recommendations in this report are intended to improve TVA's competitive position into the future.

SELF-IMPOSED DEBT LIMITATION

The three major concerns identified in the IRP to date—debt, competitiveness, and the future of the four nuclear units—are interrelated. In the opinion of many TVA customers and members of the public, high debt is generally associated with a poor competitive position. Since the large capital expenditures necessary to complete TVA's nuclear units will increase TVA's debt, completing these units contributes to a perception that TVA's competitiveness will suffer. With the rapid evolution of the utility industry into a competitive environment, many utilities are improving their debt structure so that the pricing of electricity can be more flexible in response to future uncertainty. Clearly, with the increasing risk of TVA losing customers to other utilities, prudent business practices suggest that debt be carefully managed and controlled. With this in mind, the TVA Board of Directors requested the CFO to initiate a study to investigate the possibility of stopping the growth of debt. This study, "Report on Controlling the TVA Debt," was completed in December 1994. The following Introduction and Conclusion of the CFO study highlight several key points concerning TVA's debt:

FIGURE T8-57. **Commercial Costs – Calendar Year 1993**

Kentucky Utilities	4.3 ¢/kWh
Public Service of Indiana	4.6
Kingsport Power	5.1
Kentucky Power	5.2
Appalachian Power (VA)	5.3
Ohio Power	5.5
Louisville Gas & Electric	5.6
Gulf Power	5.6
South Carolina Elec. & Gas	5.6
Florida Power	5.8
TVA	**5.9**
Mississippi Power	6.0
Duke Power	6.0
Virginia Power	6.2
Union Electric	6.3
Florida P&L	6.8
East Kentucky Power	6.8 [1]
Big Rivers	6.9
Carolina P&L	6.9
Alabama Power	6.9
Gulf States Utilities	7.3
Georgia Power	7.4
Arkansas P&L	7.6
Louisiana P&L	7.8
Illinois Power	8.3
New Orleans Pub Ser	8.4
Mississippi P&L	8.6

[1] Using South Kentucky REC Corp. as representative of East Kentucky Power Coop

Source: DOE 826, REA Forms 7 & 12, and TVA Electric Sales Statistics

"At the Tennessee Valley Authority Board of Directors meeting on September 21, 1994, the Board of Directors requested that the Chief Financial Officer undertake a study to determine if it would be possible to stop the growth of debt in TVA and, in effect, impose an internal limitation on debt below TVA's statutorily mandated limit of $30 billion. If that is possible, what should that limit be and when could it be achieved.

"The results of this review, which has encompassed the involvement of all areas of the TVA, is that TVA can limit its level of debt to $2 billion to $3 billion below the $30 billion debt ceiling and can achieve this limitation by the end of fiscal year 1997."

The internal debt limit would be formally reviewed periodically to ensure that this limitation meets TVA's continuing business needs.

Additionally, the Board of Directors is requesting that the CFO conduct a feasibility study of reducing future levels of debt.

The debt limit will be carefully observed in the development of TVA's IRP. In addition, the IRP will examine the disposition of TVA's debt in light of an increasingly competitive business environment.

I. Key Assumptions for Evaluating TVA's Nuclear Construction Program

Although many assumptions about possible futures must be made to evaluate TVA's nuclear construction program, two key assumptions are both important and highly uncertain. These are the need for power, which is largely determined by the expectations of future load growth, and the cost and performance parameters for constructing and operating TVA nuclear power plants.

NEED FOR POWER

TVA will likely require additional power beginning in 1998 and increasing to several thousand megawatts (MW) by 2005. This need is shown graphically in *Figure T8-59*.

The bars in *Figure T8-59* represent TVA's long-term forecasts of peak loads plus the necessary capacity reserves to maintain a reliable power system. TVA's peak loads are approximately 24,000 MW today and are expected to increase 1.9 percent per year from 1994 to 2020. Forecasts of future load growth are particularly uncertain, and this uncertainty is represented by low

FIGURE T8-58. **Industrial Costs – Calendar Year 1993**

Big Rivers	3.0 ¢/kWh [1]
Ohio Power	3.2
Kentucky Utilities	3.3
Kentucky Power	3.3
Public Service of Indiana	3.4
Kingsport Power	3.5
Mississippi Power	3.6
Louisville Gas & Electric	3.8
Appalachian Power (VA)	3.8
South Carolina Elec. & Gas	3.9
TVA	**3.9** [2]
Louisiana P&L	4.1
Duke Power	4.3
Gulf Power	4.3
Illinois Power	4.4
Virginia Power	4.4
Alabama Power	4.5
Gulf States Utilities	4.6
Georgia Power	4.7
Florida Power	4.8
Union Electric	5.2
New Orleans Pub Ser	5.3
Florida P&L	5.4
Carolina P&L	5.5
East Kentucky Power Coop	5.5 [3]
Arkansas P&L	6.0
Mississippi P&L	6.6

1 Non-Aluminum Industrial is 3.9 cents/kWh
2 TVA's directly served industrial cost is 3.0 cents/kWh and the distributor served industrial cost is 4.6 cents/kWh
3 Using South Kentucky REC Corp. as representative of East Kentucky Power Coop

Source: DOE 826, REA Forms 7 & 12, and TVA Electric Sales Statistics

and high forecasts of peak load, which generally bound the range of uncertainty. In the low load forecast, peak loads are expected to increase by 0.1 percent per year from 1994 to 2020, and in the high forecast by 3.3 percent per year over the same period. In *Figure T8-59*, the three segments of each bar represent TVA's low, medium, and high demand requirements for that year.

TVA currently has approximately 25,500 MW of existing capacity, with a plan to add 2,235 MW upon the completion of Watts Bar Unit 1 and the return to service of Browns Ferry Unit 3. This existing and future capacity, or supply, is shown by the solid line in *Figure T8-59*.

Matching the supply with projected future demand requirements (comparing the bars to the supply line in *Figure T8-59*) indicates that TVA's need for additional capacity will increase from 700 MW in 1998 to several thousand megawatts by 2005. It must be recognized that these capacity needs are highly uncertain. With low demand requirements, there is no need for future capacity from 1996 to 2020; whereas, with high load growth, there is an almost immediate need for additional capacity.

NUCLEAR COSTS AND PERFORMANCE

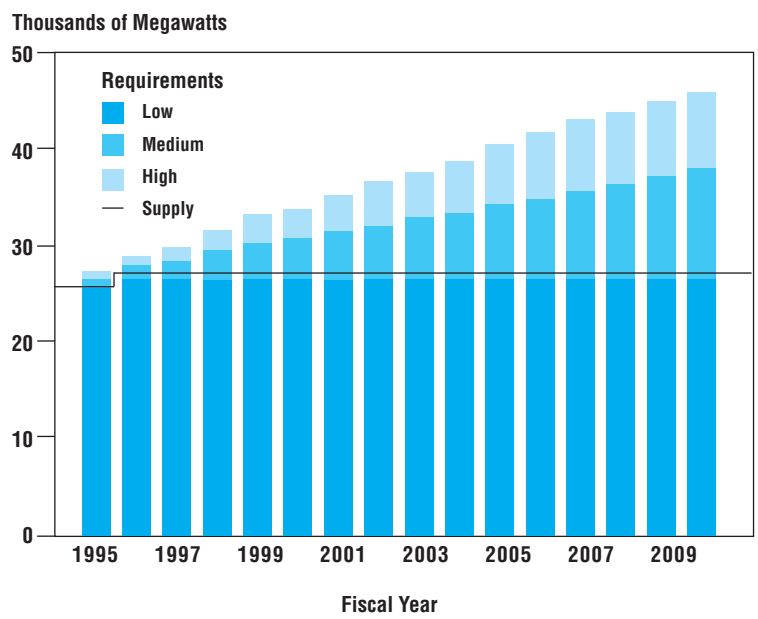
The question of whether to complete/restore the nuclear units is affected by several key assumptions about nuclear construction and operation. Most important are the cost to complete the nuclear units, the cost to operate and maintain the units, and the level of generation from the units or capacity factors. Of lesser significance are the fuel costs and costs to decommission the nuclear plants at the end of their useful lives, currently estimated to be at least 40 years. The future construction cost and operational performance of the nuclear units cannot be precisely forecast and this uncertainty in cost and performance is represented by a range of forecasts for these key assumptions.

Project Cost and Schedule Estimates

Both the expected, or medium, forecast and the low and high forecasts for the cost to complete the nuclear units are shown in *Figure T8-60*.

The medium and high-cost estimates are based on detailed engineering cost estimates plus adjustments reflecting the history of cost-estimating experience by TVA and the nuclear industry. The detailed engineering cost estimates that have

FIGURE T8-59. **Long-Term Capacity Requirements and Supply**



been developed for each of the nuclear projects serve as the "low" estimate for IRP analysis.

Capacity Factors

Capacity factor is a ratio of actual generation from a generating unit compared to its theoretical best output over a certain period of time. TVA's average annual nuclear capacity factor since restoring Sequoyah Units 1 and 2 and Browns Ferry Unit 2 to service has been 67 percent. This value is used as the medium estimate for future capacity factor for the currently operating units (Sequoyah Units 1 and 2 and Browns Ferry Unit 2), for projects under active construction or modification (Watts Bar Unit 1 and Browns Ferry Unit 3), and for the currently inactive projects (Watts Bar Unit 2, Browns Ferry Unit 1, and Bellefonte Units 1 and 2). TVA's high and low estimates for nuclear capacity factor are 86 percent and 55 percent, respectively. Industry trends have shown significant improvement in nuclear performance over the past decade.

Operating Costs

Operating costs for a nuclear unit include "operations and maintenance," "additions and improvements," and fuel. In addition, funds are accumulated for decommissioning throughout the life of the unit. These cost estimates are shown in *Figure T8-61*.

Operations and maintenance cost assumptions are based on the costs incurred by TVA for the operating units over the past five years. The range of potential costs is based on potential variations in plant staffing levels, since this is the primary driver for nuclear operations and maintenance costs.

The cost of additions and improvements has dropped significantly throughout the nuclear industry with the completion of regulation-driven modifications required after the 1979 Three Mile Island accident. TVA is assuming a level of expenditures consistent with industry experience. Replacing steam generators at Sequoyah Units 1 and 2 and Watts Bar Units 1 and 2 is an unusual addition and improvement and is considered explicitly in the IRP analysis.

Nuclear fuel costs at TVA have been higher than average because of contracts written during the 1980s. As these contracts have expired, TVA will be procuring fuel at a cost typical of the industry. Nuclear fuel is relatively abundant now, and sufficient supplies are expected to be available throughout the period of the IRP to limit cost escalation to that of general inflation.

Decommissioning costs are accrued and set aside during the operating life of the plant in accordance with rules issued by the Nuclear Regulatory Commission (NRC). Current cost estimates for decommissioning exceed these NRC requirements. TVA has identified a range of possible decommissioning costs for consideration in the IRP assumptions that use the NRC-required level as a low estimate.

FIGURE T8-60. **Nuclear Project Cost and Schedule Estimates**

	Cost Estimate (millions of 1994 dollars)			Nominal Schedule
Project	Low	Medium	High	(months)
Bellefonte Unit 1	1311	2622	3470	67
Bellefonte Unit 2	912	1824	2420	*
Browns Ferry Unit 1	1187	2374	3150	78
Watts Bar Unit 2	1097	2194	2910	62

** Approximately 18 months after Bellefonte Unit 1 is completed*

FIGURE T8-61. **Nuclear Operating Costs (in 1994 dollars)**

	Low	Medium	High
Operations & Maintenance	$55/kW/yr	$69/kW/yr	$84/kW/yr
Additions & Improvements		Approx. $15 million/unit/yr	
Incremental Fuel		$0.42/million Btu	
Decommissioning			
• Pressurized Water Reactors	$ 200 million	$ 300 million	$ 600 million
• Boiling Water Reactors	$ 250 million	$ 350 million	$ 700 million

License Extension

Operating licenses for the Browns Ferry units expire during the time period covered by the IRP. The NRC issued regulations in 1991 that allow an operator to apply for a license extension of up to 20 years. These rules are currently being revised and are not expected to be finalized until mid-1995. Consequently, the cost and schedule for obtaining a license extension cannot be defined with certainty. Technical studies, however, have not shown any "show-stoppers" that would preclude extending the Browns Ferry licenses. To accommodate this possibility, the IRP will consider both extending the operating licenses at these units and terminating their operation at the current license expiration date.

THE CONVERSION ALTERNATIVE

Figure T8-62 provides a cost and performance summary for converting the Bellefonte nuclear units to fossil-fueled units. Four alternative conversion options are considered: coal-fired plant, natural gas combined cycle, integrated gasification combined cycle, and integrated gasification combined cycle with coproduction of a chemical product such as methanol or methyl tertiary butyl ether.

THE CANCELLATION ALTERNATIVE AND REPLACEMENT WITH SUPPLY- OR DEMAND-SIDE RESOURCES

The key assumptions for supply- and demand-side alternatives that are available to replace the nuclear units are too numerous to display in this paper. However, the cost and performance characterizations for each supply option are identified in the paper, "Energy Vision 2020 Supply-Side Options." Cost and per-

FIGURE T8-62. **Cost and Performance Summary**

	Pulverized Coal, 4x616 MW	Gas-Fired Combined Cycle 10x222 MW	IGCC, 9x250 MW	IGCC with Coproduction, 9x239 MW (feasibility only)
Capacity, MW	2,464	2,220	2,250	2,151
Heat Rate, Btu/kWh	9,611	7,367	8,488	11,761
Fuel [1]	Illinois Basin 3.0 lb SO_2 Coal	Natural Gas	Illinois Basin 7.0 lb SO_2 Coal	Illinois Basin 7.0 lb SO_2 Coal
Capital Cost, [2] $/kW (1994)	$1,263 (base) $1,158 (low) $1,325 (high)	$475 (base) $442 (low) $507 (high)	$1,484 (base) $1,327 (low) $1,650 (high)	$1,730 (base) $1,530 (low) $1,942 (high)
Total Capital Cost, MM$ (1994)	$3,112 (base) $2,853 (low) $3,265 (high)	$1,054 (base) $981 (low) $1,125 (high)	$3,339 (base) $2,986 (low) $3,712 (high)	$3,721 (base) $3,291 (low) $4,177 high)
Coproduct	none	none	none	Methyl Tertiary Butyl Ether
Coproduction Rate, Tons/Day	none	none	none	4,410 tpd
Schedule, Months First Capacity Addition [3]	90 months	66 months	66 months / 81 months [4]	66 months / 81 months [4]
Last Capacity Addition	126 months	90 months	90 months / 108 months [4]	90 months / 108 months [4]

1 Fuel SO_2 is given in terms of pounds of sulfur dioxide produced per million Btus fired.
2 Base capital cost is the expected cost. The high and low ranges define the potential range of capital costs given the uncertainties that have been identified.
3 Duration to first capacity addition assumes approximately 3 years from project initiation to start of construction for environmental permitting activities. This duration may be reduced to 18 months if credit can be taken for previously collected environmental data.
4 First duration assumes phased construction with gas-fired generation coming on-line first, followed by conversion to integrated gasification combined cycle at a later date. Second duration assumes that project proceeds directly to integrated gasification combined cycle without phased construction.

formance characteristics for the demand-side options can be found in "Energy Vision 2020 Customer Service Options."

Canceling the nuclear projects also involves liquidating the asset. Past experience with nuclear project cancellations has shown that there is essentially no net recovery from the existing equipment by the time the project is closed. The IRP, therefore, assumes no net proceeds from canceling the units.

The undepreciated value of the projects, shown in *Figure T8-63*, must also be recovered following cancellation. TVA is investigating the possibility of using recovery periods of up to 30 years.

FIGURE T8-63. **Current Undepreciated Nuclear Project Investments**

	Bellefonte Unit 1	Bellefonte Unit 2	Watts Bar Unit 2	Browns Ferry Unit 1
Current Undepreciated Investment	$ 3.7 Billion	$ 0.8 Billion	$ 1.7 Billion	$ 0.7 Billion

THE DEFERRAL OPTION

The cost of maintaining a nuclear project in a condition that would permit it to be completed at a later date is approximately $10 to $20 million per unit per year. Deferring the decision to a subsequent IRP would allow additional time to acquire information regarding nuclear unit performance and economics, TVA's need for power, and the possible role of nuclear power in minimizing total environmental impacts.

II. Evaluation of Alternatives

Based on the assumptions outlined in the previous section, the alternative nuclear strategies will be evaluated against several key criteria. These criteria (and their measurements), shown in *Figure T8-64*, were developed for the IRP process.

In the full IRP process, each nuclear strategy is evaluated against the criteria in *Figure T8-64*. For example, a strategy to complete the nuclear units is compared to a strategy to replace them with other options, such as coal-fired units. This comparison or trade-off would tell us which strategy (nuclear or coal) would have the lowest costs (total resource costs), lowest rates, least impact on debt, and most flexibility.

FIGURE T8-64. **Evaluation Criteria and Measurements**

Criteria	Measurement
Long-Run Cost and Value	Total Resource Costs Rate Impact Measure Participant Test/Electric Bill Total Value
Rates/Competitiveness	Electric Rates (Cents/kWh) 1996-2000, 1996-2005
Reliability	Reserve Margin Load Not Served
Environment	Emissions (SO_2, CO_2, NO_X, VOC, TSP, etc.) MWh Nuclear Generation
Economic Development	Jobs, Total Personal Income
Financial	Borrowings, Debt, Cash Flow, Net Income
Risk Management	Robustness, Flexibility

Not all of the IRP criteria will be used for the evaluations in this report, but some will be represented as constraints in evaluating the strategies. For example, for each strategy evaluated, the reliability of the power system will be maintained, using a 13 percent capacity reserve margin. Under the environmental criteria, all strategies are evaluated assuming compliance with Phase I and II of the acid rain provisions of the Clean Air Act and compliance with the voluntary goals for greenhouse gas emissions of the Climate Challenge Program.

The criteria for economic development will not be addressed in this report but will be addressed through the IRP.

In this report, strategies will be evaluated specifically on long-term cost (total resource cost), electric rates, and total debt, reflecting the many concerns expressed about TVA's costs and flexibility.

EVALUATING NUCLEAR STRATEGIES – THE PROCESS

Many different strategies were developed as combinations of the nuclear options, supply-side replacement options, and demand-side options. For the purposes of this report, the focus has been narrowed to a few key strategies and the resulting changes in costs, rates, debt, and flexibility. (For a complete description of all strategies and their development, see TVA's Nuclear Options Appendix.)

In evaluating the strategies, the staff looked for those that will minimize long-term costs, minimize short-term rates, minimize long-term debt, and be flexible enough to adapt to an uncertain future. In particular, the staff investigated whether there are strategies better than TVA funding the completion of the four nuclear units. In the analysis, several successive strategies were evaluated—each of which improves TVA's position in one or more of the areas of cost, rates, debt, or flexibility. These strategies are grouped as:

- Completing the nuclear units, as opposed to replacing them with alternative supply- and demand-side resource options
- Converting Bellefonte to another technology

- Completing Bellefonte as a nuclear plant, but with a partner providing funds to complete the plant
- Deferring Watts Bar Unit 2 and Browns Ferry Unit 1 to provide flexibility for an uncertain future

Each of these successive evaluations results in a potential improvement in long-term costs, short-term rates, long-term debt, and flexibility compared to TVA funding completion of the nuclear units. Exactly which strategy or strategies will be pursued as an alternative to completing the nuclear units will be determined through TVA's IRP.

Completing the Nuclear Units vs. Replacement

Five specific nuclear completion strategies are evaluated in this analysis:

1. Complete Bellefonte Units 1 and 2, Watts Bar Unit 2, and Browns Ferry Unit 1
2. Complete Bellefonte Unit 1, Watts Bar Unit 2, Browns Ferry Unit 1, and replace Bellefonte Unit 2
3. Complete Watts Bar Unit 2, Browns Ferry Unit 1, and replace both Bellefonte Units 1 and 2
4. Complete Watts Bar Unit 2 and replace Bellefonte Units 1 and 2 and Browns Ferry Unit 1
5. Replace all four units: Bellefonte Units 1 and 2, Watts Bar Unit 2, and Browns Ferry Unit 1.

Supply-Side Options: For each of these strategies, the supply-side replacement options considered were natural gas-fired combined cycle units (CC) in the short term and, for the long term, clean coal units (advanced integrated gasification combined cycle (IGCC). Peaking capacity was supplied by combustion turbines. Many different supply-side resource options were evaluated for replacement capacity. These included coal-based capacity, natural gas-based capacity, renewables, and purchases of power from cogenerators, other utilities, and independent power producers. Some of the lower-cost options in the short term were coal-fired units and combined cycle units. In the long term, natural gas-based options, renewables, and clean coal technologies such as integrated gasification combined cycle units were lower in cost. An alternative in the short term to replacing the nuclear units with combined cycle units would be to replace the units with a combination of TVA-financed combined cycle units and purchases of power from other utilities, cogenerators, or independent power producers. Such a strategy would also produce a combination of relatively low long-term costs, low short-term rates, and lower debt.

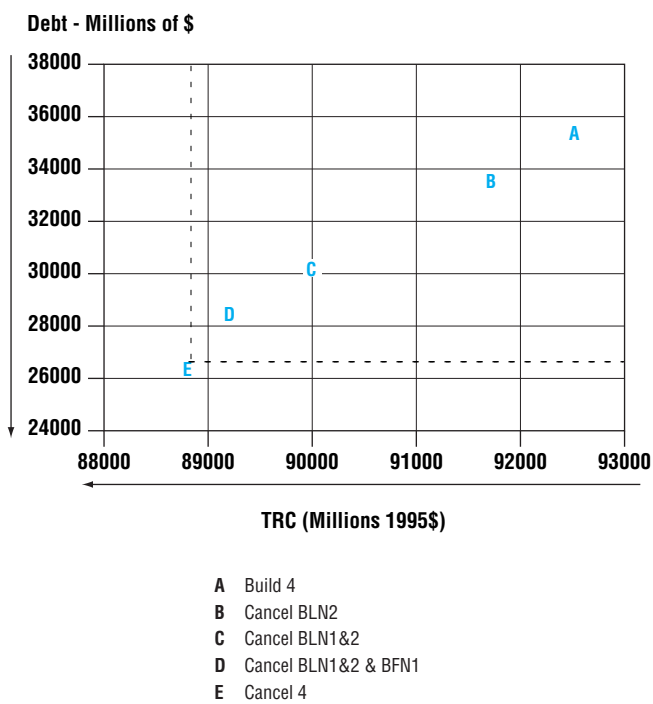
Demand-Side Options: Several combinations of demand-side options were also evaluated. For this report, the demand-side replacement option was a 700-megawatt block of programs (installed by 2005) that is both low in long-term cost and does not increase electric rates over the short term.

In all cases, the environmental strategy for compliance with Phase II acid rain regulations is based on a combination of switching to low-sulfur coal at several plants and building a scrubber at Paradise Unit 3 and the Allen Steam Plant.

The supply-side, demand-side, and environmental strategies will be thoroughly reviewed in the IRP process.

A comparison of the five nuclear completion/replacement strategies for long-term total resource costs (TRC) and total debt in the year 2007 is represented in *Figure T8-65*.

FIGURE T8-65. **Nuclear Decision Trade-Off: Low-Price DSM, Current Clean Air, CC/Coal – Total Resource Costs vs. Debt in Year 2007**

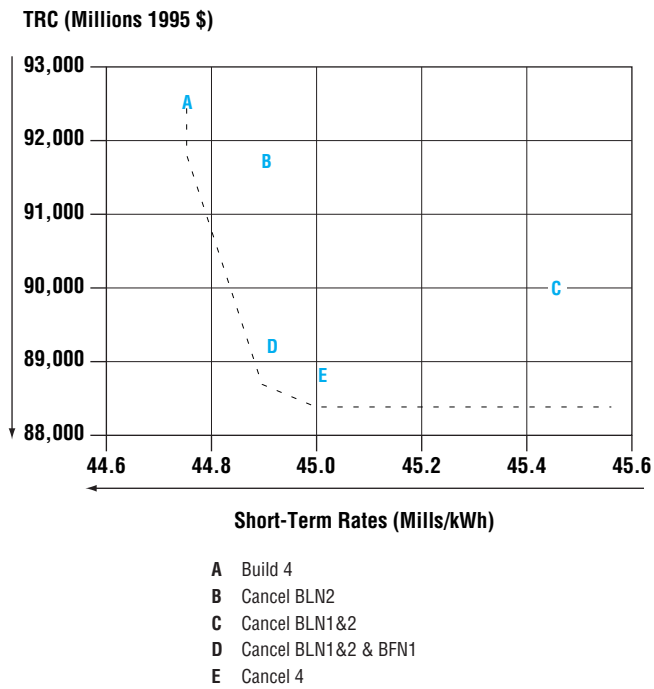


In *Figure T8-65*, the trade-off between long-term cost (TRC on the horizontal axis) and debt in the year 2007 (vertical axis) is shown for the five strategies. The results indicate that completing the four nuclear units (A) has the highest debt and highest cost compared to other strategies. The strategy that results in the lowest cost and lowest debt is to replace all four nuclear units with alternative supply- and demand-side resource options. The other strategies indicate that not completing various combinations of the nuclear units and replacing them with other resource options would result in successively lower long-term cost and debt.

A comparison of these same five strategies for long-term cost and short-term electric rates (average from 1996 to 2000) is shown in *Figure T8-66*.

Long-term costs are a measure of the long-term economic efficiency of the power system and short-term rates are a measure of short-term competitiveness. Short-term viability is extremely important as the electric utility industry is deregulated and competition or competitive pressures increase. Low rates will be an important measure of success.

FIGURE T8-66. **Nuclear Decision Trade-Off: Low-Price DSM, Current Clean Air, CC/Coal – Short-Term Rates vs. Total Resource Costs**



The comparison of the five strategies indicates a trade-off between long-term TRC and short-term rates, as indicated by the dashed trade-off line. Building all four nuclear units results in the highest cost and lowest rates, whereas replacing all four units results in lower cost and a slight increase in rates. Replacing only Bellefonte Units 1 and 2 (C) results in lower costs but increased short-term rates. The short-term rate increase would result from an increase in revenue needed to write off previously spent (sunk) capital expenditures on the nuclear units if these units are replaced.

Replacing all four nuclear units has a lower effect on rates than replacing Bellefonte Units 1 and 2 only. One might expect that replacing all four units would have a greater effect on short-term rates than simply replacing two units, since the write-off of sunk cost for four units is greater. However, the short-term rate increases are less when replacing four units because of other cost savings. The lower cost-to-complete, capital additions and improvements, and operation and maintenance costs for Browns Ferry Unit 1 offset the increase in revenue needs due to write-offs.

Converting Bellefonte to Another Technology

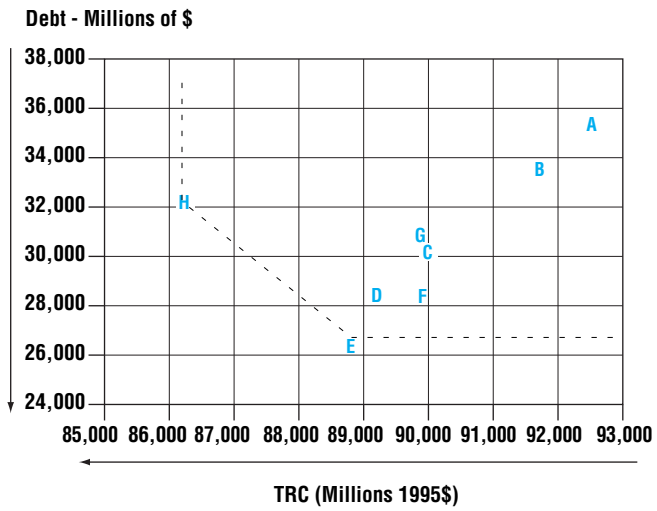
Three strategies for converting Bellefonte Units 1 and 2 to an alternative technology are:

1. Convert to a natural gas-fired combined cycle (CC)
2. Convert to an integrated gasification combined cycle unit (IGCC) in which coal is gasified and the synthesis gas is used in a combined cycle unit
3. Convert to an integrated gasification combined cycle plant where some of the synthesis gas is used to produce a chemical coproduct such as methanol (IGCC/P)

Converting Watts Bar Unit 2 or Browns Ferry Unit 1 to another technology is less feasible because there are, or will be, operating nuclear units at these sites. Although not completely infeasible, the shared systems would make conversion extremely difficult from a technical viewpoint. Thus, for this report, converting Watts Bar Unit 2 and Browns Ferry Unit 1 are not considered.

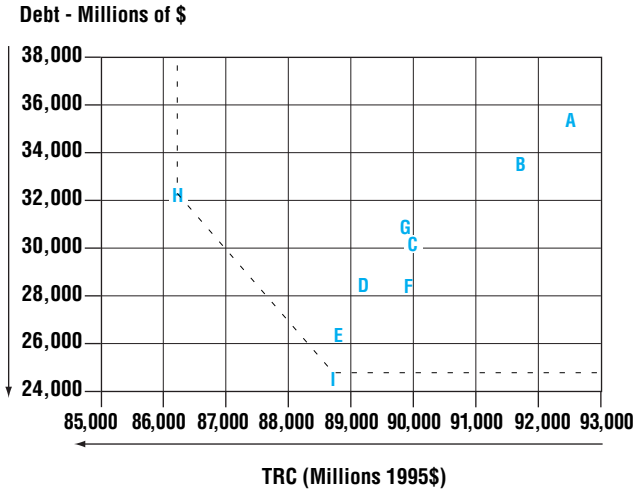
These three Bellefonte conversion strategies are compared to the completion and replacement strategies previously evaluated. For comparison purposes, all of the conversion strategies assume that Watts Bar Unit 2 and Browns Ferry Unit 1 are replaced by the same supply- and demand-side options as in the previous comparisons. The completion, replacement, and conversion strategies are shown in *Figure T8-67* for long-term costs and total debt in 2007.

FIGURE T8-67. **Nuclear Decision Trade-Off: Low-Price DSM, Current Clean Air, CC/Coal – Total Resource Costs vs. Debt in Year 2007**



A	Build 4	**E**	Cancel 4
B	Cancel BLN2	**F**	Cancel CC Conv
C	Cancel BLN1&2	**G**	Cancel IGCC Conv
D	Cancel BLN1&2 & BFN1	**H**	Cancel IGCC/P Conv

FIGURE T8-68. **Nuclear Decision Trade-Off: Low-Price DSM, Current Clean Air, CC/Coal – Total Resource Costs vs. Debt in Year 2007**



A	Build 4	**F**	Cancel CC Conv
B	Cancel BLN2	**G**	Cancel IGCC Conv
C	Cancel BLN1&2	**H**	Cancel IGCC/P Conv
D	Cancel BLN1&2 & BFN1	**I**	Defer & Partner
E	Cancel 4		

The conversion options (F,G, and H) compared to replacing all the nuclear units (E) have higher debt associated with them. The conversion to combined cycle (F) and integrated gasification combined cycle (G) also tends to increase costs by approximately $1 billion. The conversion to an integrated gasification plant with a chemical coproduct (H), although increasing debt, does lower long-term costs by approximately $3 billion compared to replacing all of the nuclear units (E).

Although not shown in *Figure T8-67*, the conversion to combined cycle or the conversion to integrated gasification combined cycle with a coproduct (IGCC/P) have about the same effect on short-term rates as replacing all of the nuclear units.

The conclusion from this comparison is that converting Bellefonte to a combined cycle (CC) plant increases long-term cost and debt slightly compared to replacement, but appears to be a viable alternative to completing Bellefonte as a nuclear plant. The conversion to integrated gasification combined cycle with a chemical coproduct (IGCC/P) can significantly reduce long-term costs but significantly increases debt. To reduce the impact on debt for the conversion to a plant that produces a coproduct, TVA is exploring an option for a partnership to build the IGCC/P plant. This option will be fully explored in the IRP process.

Bellefonte Nuclear Partnership

Another strategy currently being explored by TVA is to enter into a partnership with another firm to complete Bellefonte as a nuclear plant. In this arrangement, the partner would complete the construction of the nuclear plant and TVA would buy a part or all of the electricity produced at predetermined prices. Any profits from the sale of electricity would be returned to TVA and the partner(s). This partnership strategy is compared to the completion, replacement, and conversion strategies in *Figure T8-68*.

The Bellefonte partnership strategy is shown in *Figure T8-68* as an 'l'. Based on preliminary assessments of the potential for a partnership arrangement, this strategy could reduce long-term cost and debt compared to replacing Bellefonte with alternative supply- or demand-side resource options. Thus, a partnership for Bellefonte will be fully evaluated in TVA's IRP.

UNCERTAINTY IN KEY ASSUMPTIONS

The strategies to complete the nuclear units, replace the nuclear units, convert Bellefonte, or enter into a partnership to complete Bellefonte as a nuclear plant have been evaluated based on a mid-range set of assumptions discussed in the previous section. All of the evaluations have been based on a mid-range future that includes:

- The mid-range load forecast
- The mid-range cost and operating characteristics for the nuclear plants
- Other assumptions necessary for the evaluations

Basing the evaluations solely on the mid-range assumptions implies that we can perfectly forecast the future. Since no one has perfect foresight, it is necessary to evaluate the nuclear strategies using different assumptions about the future. Under the IRP, over 30 different parameters already have been analyzed, as well as how variations in these parameters can change the evaluations of these strategies. From these analyses, we have identified the most important parameters or uncertainties whose variation could alter the evaluations of the nuclear strategies. These uncertainties are:

- The load forecast
- The cost to complete the nuclear plants
- The operations and maintenance cost for the nuclear plants
- The capacity factor of the nuclear plants
- Whether there will be future legislation on carbon dioxide (CO_2) emissions or greenhouse gases

Further evaluations have indicated that decisions concerning completing the nuclear units versus replacing them would not be affected by possible future legislation on CO_2 emissions. In these evaluations, CO_2 was valued at $5 and $10 per ton. Before it became a significant decision factor, CO_2 would have to be valued at approximately $30 per ton.

To examine uncertainty, the nuclear strategies have been evaluated for two alternative futures as compared to the mid-range assumptions. To derive these futures, we have varied the load forecast, the cost-to-complete, the operation and maintenance cost, and the capacity factor of the nuclear units. The first future is a "low performance" future consisting of:

- Low load growth
- High cost-to-complete the nuclear units
- High operations and maintenance costs of the nuclear units
- Low nuclear capacity factor

The second "high performance" future consists of:

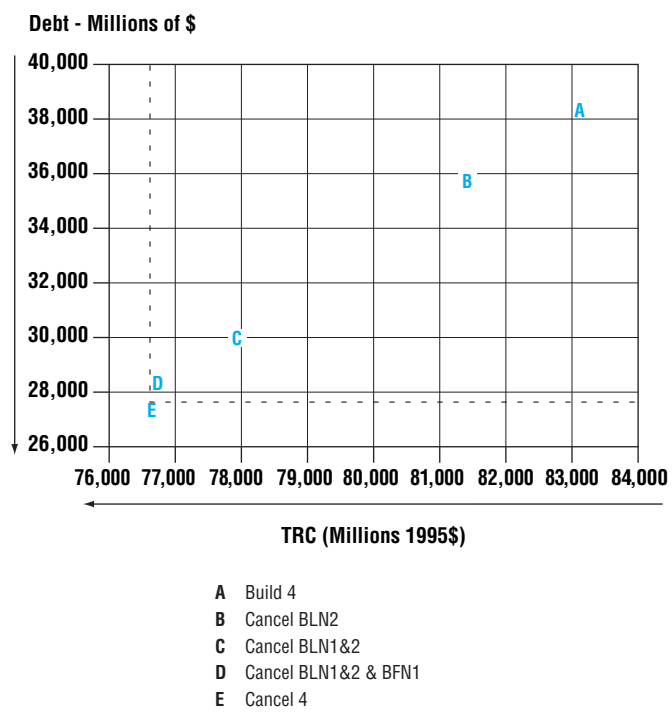
- The high load forecast
- Low cost-to-complete the nuclear units
- Low operations and maintenance costs
- High nuclear capacity factor

A Comparison of Nuclear Completion and Replacement with Alternative Futures

The effect on long-term cost and debt for the five nuclear completion and replacement strategies for the "low performance" future is shown in *Figure T8-69*.

In *Figure T8-69* the lowest cost and lowest debt option is to replace all four nuclear units with alternative supply- or demand-

FIGURE T8-69. **Nuclear Decision Trade-Off: "Low Performance" Future – Total Resource Costs vs. Debt in Year 2007**

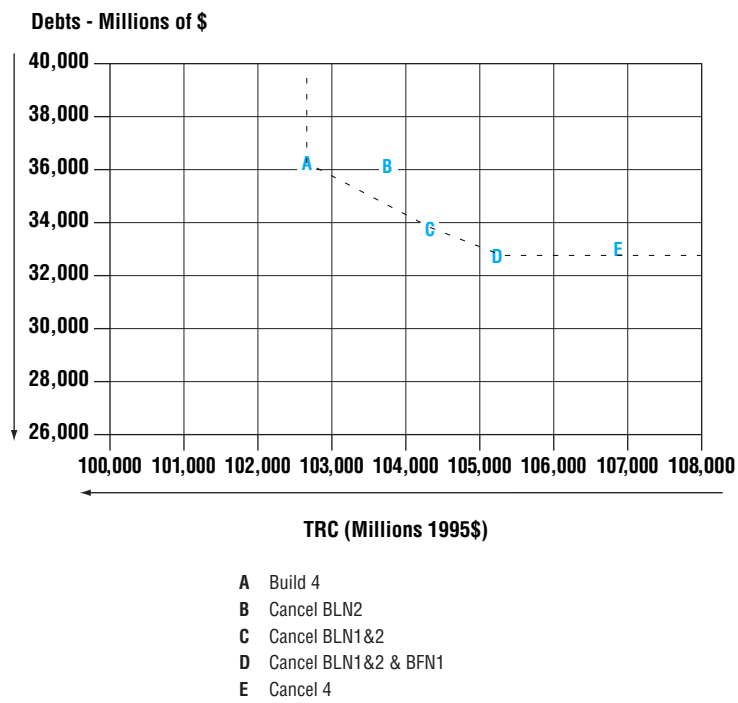


side options. This result is the same as for the "mid-range forecast" shown in *Figure T8-59* in the "Key Assumptions" section.

The same strategies evaluated with the "high performance" future are shown in *Figure T8-70*.

In *Figure T8-70*, the five nuclear completion and replacement strategies are evaluated for the "high performance" future and the resulting impacts on long-term costs and debt are represented. These results differ from previous results in that the lowest-cost option is to complete the nuclear units (A) compared to canceling the units (E). Completing the units (particularly the Bellefonte units) generally results in higher debt when compared to replacing them (A and E).

FIGURE T8-70. **Nuclear Decision Trade-Off: "High Performance" Future – Total Resource Costs vs. Debt in Year 2007**



SUMMARY OF ALTERNATIVE FUTURES

For the "mid-range" future and "low performance" future, the lowest long-term cost and debt strategy was the strategy to replace all four of the nuclear units. For the "high performance" future, the completion of Watts Bar Unit 2 and Browns Ferry Unit 1 could reduce costs compared to replacing the units and not significantly increase debt in 2007. Thus, if we could predict for certain that the "high performance" future would occur, costs could be reduced by completing Watts Bar Unit 2 and Browns Ferry Unit 1 compared to replacing the units.

An alternative that would allow TVA to gain additional information about load growth and nuclear performance would be to defer until a later time the decision to complete or replace the nuclear units. If, in the near future, the "mid-range performance" or the "low performance" future appears more likely, the nuclear units could be replaced. If the "high performance" future seems likely, then the nuclear units could be completed. The additional cost of such a strategy is the cost of keeping the nuclear units in a deferred status, or approximately $10 to $20 million per year per unit.

Deferral of the Decision on Watts Bar Unit 2 and Browns Ferry Unit 1

Since there are clearly several strategies available for the completion and conversion of the Bellefonte units, an attractive strategy may be to defer the decision to complete or replace Watts Bar Unit 2 and Browns Ferry Unit 1 for several years. An evaluation of a strategy to defer the decision on these units until the year 2000 is shown in *Figures T8-71* and *T8-72*.

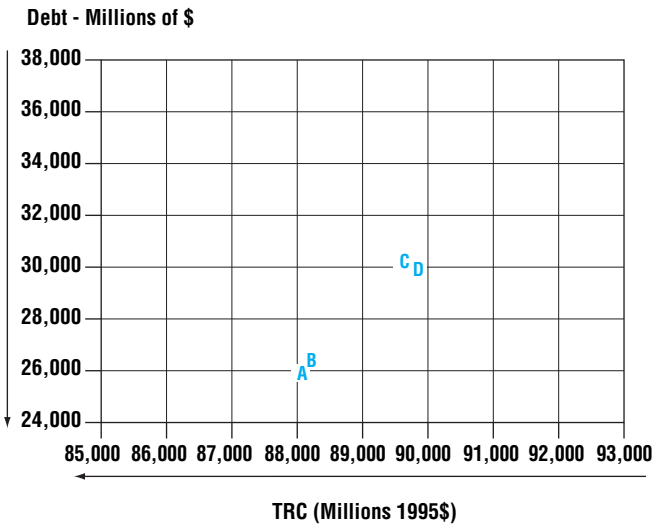
Figure T8-71 indicates that deferral does not significantly raise long-term cost or debt compared to immediately replacing the nuclear units or replacing Watts Bar Unit 2 and Browns Ferry Unit 1.

Deferring the decision to either complete or replace these two units provides flexibility to adapt to significantly different futures. With the "medium or low performance" future, the decision can be made to replace these two units. With the "high performance future," the decision can be made to complete construction of the nuclear units. The value of this flexibility is estimated to be about $200 million more than the costs of keeping the nuclear units in a deferred status.

Deferring a decision on Watts Bar Unit 2 and Browns Ferry Unit 1 also has a favorable impact on short-term rates as shown in *Figure T8-72*.

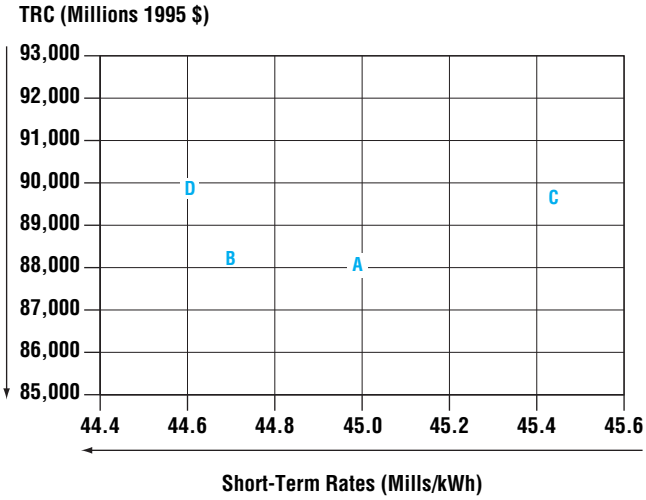
In *Figure T8-72*, the continued deferral of both nuclear units is represented by 'D' if the deferred units are completed and by 'B' if the units are canceled at a later date. Comparing the deferral strategies to the replacement strategies (A and C) indicates that short-term rates are reduced by deferring the decision on Browns Ferry Unit 1 and Watts Bar Unit 2.

FIGURE T8-71. **Deferral of Watts Bar Unit 2 and Browns Ferry Unit 1 Decision Trade-Off – Total Resource Costs vs. Debt in Year 2007**



A Cancel 4
B Cancel BLN1&2 Defer/Cancel WBN2 & BFN1
C Cancel BLN1&2 Build WBN2 & BFN1
D Cancel BLN1&2 Defer/Build WBN2 & BFN1

FIGURE T8-72. **Deferral of Watts Bar Unit 2 and Browns Ferry Unit 1 Decision Trade-Off – Short-Term Rates vs. Total Resource Costs**



A Cancel 4
B Cancel BLN1&2 Defer/Cancel WBN2 & BFN1
C Cancel BLN1&2 Build WBN2 & BFN1
D Cancel BLN1&2 Defer/Build WBN2 & BFN1

Thus, the continued deferral of Watts Bar Unit 2 and Browns Ferry Unit 1 can provide flexibility to adapt to a highly uncertain future and reduce short-term rate changes compared to an immediate decision to either build or replace the units.

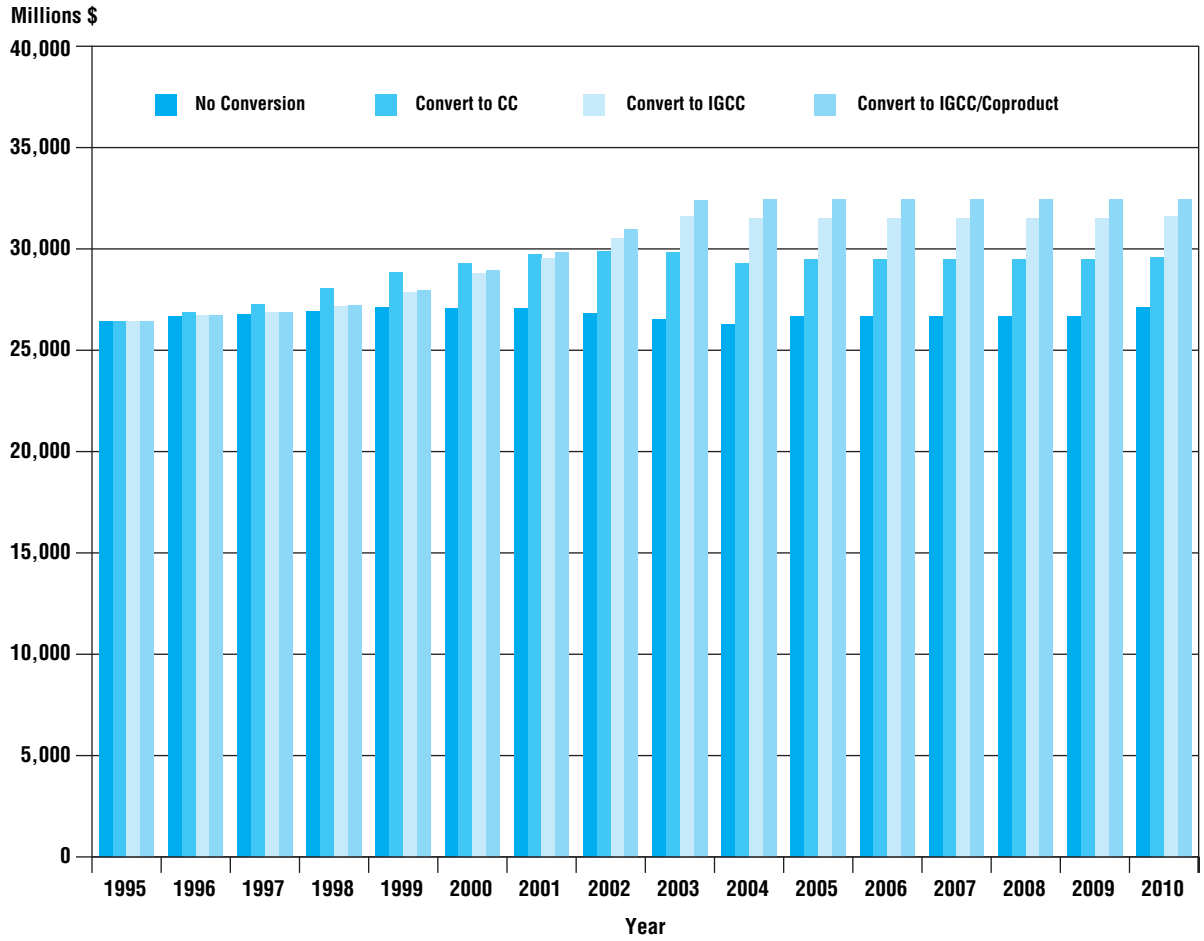
SUMMARY OF NUCLEAR STRATEGY RESULTS

Combining the different nuclear strategies is likely to produce a single strategy that minimizes debt, long-term costs, and short-term rates. Such a strategy could include:

- Completing Bellefonte as a nuclear plant with a partner
- Converting Bellefonte by TVA alone or in partnership
- Deferring a decision to complete or replace Watts Bar Unit 2 and Browns Ferry Unit 1
- Replacing capacity with combined cycle units or a combination of combined cycle units and purchases of power
- A block of demand-side management programs that minimize short-term rate changes

The change in debt from 1995 to 2010 for such a strategy is shown in *Figure T8-73*. By the end of 1995, total TVA debt will be slightly less than $27 billion. Without a conversion at Bellefonte or a conversion with a partner providing the capital funds, debt will remain slightly less than $27 billion through the year 2006. With the conversion of Bellefonte to combined cycle, debt increases to slightly less than $30 billion in the year 2002 and under the other conversion strategies, debt reaches $30 billion in the year 2002.

FIGURE T8-73. **Total Debt – Defer Browns Ferry Nuclear Unit 1 & Watts Bar Nuclear Unit 2**



Note: Expand with CC/IPP/ Coal and Low-Price DSM

III. Conclusions

Evaluations of the nuclear strategies for the long-term cost, debt, short-term rate, and flexibility criteria lead to the following conclusions:

- Continued TVA construction of Bellefonte Units 1 and 2 and Watts Bar Unit 2 as nuclear units and restoration of Browns Ferry Unit 1 lead to higher costs and prevent TVA from limiting debt.
- Alternatives which could lower costs and limit debt include:
  - Replacing the nuclear units
  - Converting Bellefonte to another technology
  - Completing or converting Bellefonte in partnership with others
- Under certain conditions in the future, nuclear generation could emerge as a low-cost option. These conditions are:
  - High load growth
  - Improved nuclear performance
- Holding the nuclear option open can lead to lower short-term rate increases and increased long-term flexibility compared to immediate decisions to either complete or replace the nuclear units. Flexibility may be enhanced by:
  - Completing Bellefonte in partnership with others ($100 million savings and reduced debt)
  - Converting Bellefonte to another technology in partnership with others
  - Deferring Watts Bar Unit 2 and Browns Ferry Unit 1 – (value of the flexibility gained by deferring these units is upwards of $200 million when compared to canceling them immediately)
- TVA should not fund the completion or restoration of Bellefonte Units 1 and 2, Watts Bar Unit 2, and Browns Ferry Unit 1 as nuclear units. Instead, TVA should keep open alternatives for these units that would minimize short-term rates, increase long-term flexibility, minimize long-term costs, and limit debt.

TVA'S NUCLEAR OPTIONS APPENDIX

Alternative Resource Strategies

Several possible strategies have been developed for the four nuclear units, Bellefonte Units 1 and 2, Watts Bar Unit 2, and Browns Ferry Unit 1. These strategies include:

1. Complete the units as nuclear units.
2. Convert them to another technology.
3. Cancel one or more of them and replace them with other supply- and demand-side technologies.
4. Defer the decision and decide at a later date either to complete, convert, or cancel the units.

Completion of the Nuclear Units

Completing the units as nuclear requires continuing the projects as currently planned with TVA performing and paying for construction. The four nuclear units are described in *Figure T8-74*.

Another option for completing the nuclear units is for TVA to enter into a partnership. Under this approach, TVA would contribute the nuclear asset as it is currently constructed to the project partnership. The other member(s) of the partnership would complete the units with non-TVA funds. The output of the plant after completion could be sold to TVA or other consumers at prearranged prices. Any profits from the sale of the electricity from the units would be shared by the partners: TVA and the other party(ies). TVA is currently exploring this type of arrangement for Bellefonte Nuclear Plant.

Conversion to Alternative Technologies

Alternatives for converting Bellefonte to a fossil-fueled facility have been considered since the late 1980s. The alternatives include converting the units to:

- Pulverized coal-fired units (PC)
- Natural gas-fired combined cycle (NGCC)
- Integrated gasification combined cycle (IGCC)
- Integrated gasification combined cycle with coproduction of a chemical byproduct

FIGURE T8-74. **Status of Nuclear Plant Construction**

	Bellefonte Unit 1	Bellefonte Unit 2	Browns Ferry Unit 1	Watts Bar Unit 2
Plant Location	Hollywood, AL	Hollywood, AL	Decatur, AL	Spring City, TN
Power Level	1212 MW	1212 MW	1065 MW	1170 MW
Reactor Type	Pressurized Water Reactor	Pressurized Water Reactor	Boiling Water Reactor	Pressurized Water Reactor
Nuclear Steam Supply System Manufacturer	Babcock & Wilcox	Babcock & Wilcox	General Electric	Westinghouse
Construction Permit Date	1974	1974	1967	1973
Construction Status	88%	57%	100%	61%
Current Undepreciated Investment	$ 3.7 Billion	$ 0.8 Billion	$ 0.7 Billion	$ 1.7 Billion

Cancel the Projects and Replace with Alternative Capacity

The four nuclear units could be replaced with many different types of supply- and demand-side resource options.

SUPPLY-SIDE OPTIONS

Supply-side options are drawn from a variety of sources. Some are traditional power supply technologies, such as the pulverized coal and natural gas-fired combined cycle options. Other supply-side options describe opportunities that are unique to TVA. Examples of this second group include completing or converting the Bellefonte Nuclear Units or increasing the capacity of the Raccoon Mountain pumped-storage facility. Still other options reflect ongoing research and development of new technologies including solar power, wind power, fuel cells, and some of the more advanced combustion technologies.

A challenge faced in developing the supply-side options catalog is to ensure that a sufficiently broad spectrum of options is identified while still keeping the total to a manageable number. Clearly the nuclear completion, conversion, and cancellation options had to be included since they represented near-term decisions that TVA needs to make. Traditional options are included to provide a comparison with previous work and because a number of these technologies are still viable options being constructed by other utilities today.

TVA also reviewed 20 other utility IRPs to determine if we had left out any important options. Comparing TVA's option list to the list extracted from the review provides some indication of reasonableness. *Figure T8-75* illustrates this comparison. With the exception of geothermal (which is not available to a significant degree in the TVA region), large solar collectors (which do not appear to be economical as compared to other solar options), and diesel generators (which are covered better as customer service options), the TVA list spans the range covered by other IRPs.

Obtaining power supply from cogenerators and independent power producers (IPPs) has become common in the utility industry. Generally, contracts for this kind of power supply are obtained through a bidding process after a utility defines its needs (in terms of capacity type, power level, and need dates). TVA has issued a request for proposals on options for future power purchases.

TVA also can buy power from other utilities. In the near term, some utilities in the region have excess generating capacity. This excess capacity is expected to be consumed by the early 2000s, however. In the longer term, power purchases from other

FIGURE T8-75. **Comparison with Options Cited in 20 Other Integrated Resource Plans**

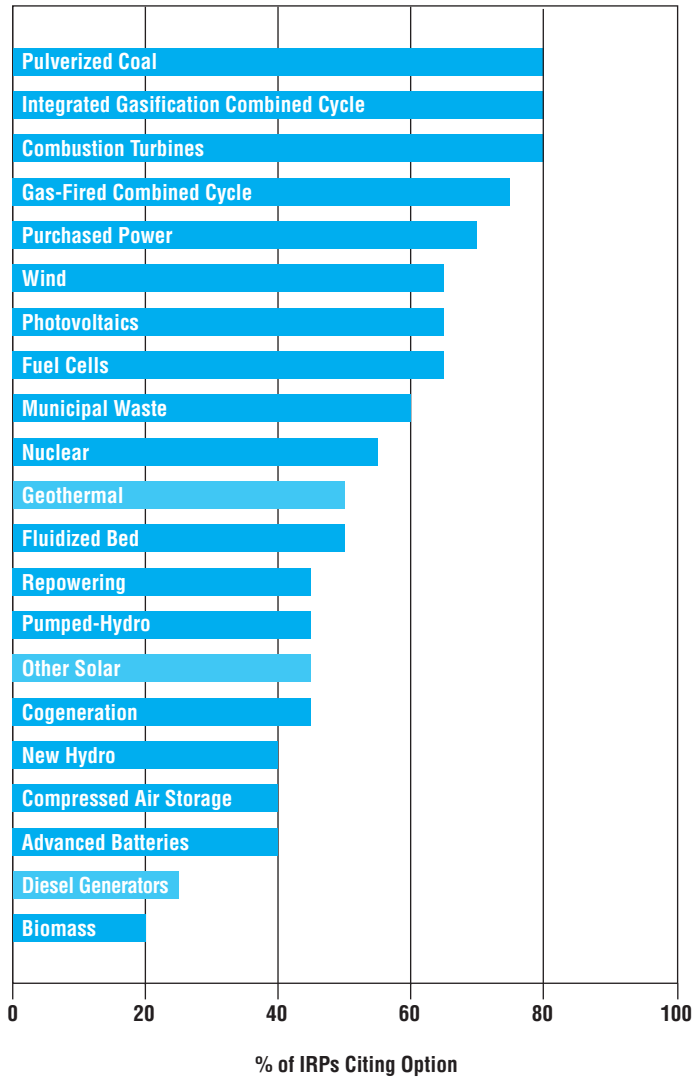


FIGURE T8-76. **Customer Service Options – Summary Impacts**

Area	Options	IMPACTS IN THE YEAR 2005 MW	GWH
Energy Efficiency	30	2,780	12,455
Self-Generation	3	146	575
Beneficial Electrification	14	-397	-1,931
Rates	3	670	-1,533

utilities will still be possible, but will likely have higher prices that reflect their cost of adding new capacity.

DEMAND-SIDE MANAGEMENT

In addition, there are over 50 different demand-side options which could be used to replace all or a part of the nuclear units. The demand-side options cover several different technologies including load management, energy efficiency, and renewables. Demand-side options have been developed for residential, commercial, and industrial customers.

TVA's customer service options were developed in four key areas:

- Energy efficiency, including conservation and load management options
- Self-generation
- Beneficial electrification
- Pricing or rate incentives

Figure T8-76 provides a summary of all options that have been developed by TVA to date for consideration in the IRP. Thirty options (17 residential and 13 commercial and industrial) have been developed in the energy efficiency classification. Three general options have been identified for the cogeneration classification. Fourteen options spanning all sectors of the economy, including the transportation sector, have been developed for beneficial electrification. These options affect both the need for new generating capacity, in terms of megawatts (MW), and the level of electricity sales, in terms of gigawatt-hours (GWH) that TVA would be required to provide. Thus, *Figure T8-76* shows that in 2005, over 2,500 megawatts of capacity savings are contained in the proposed energy efficiency options. Further, small-scale self-generation would reduce the direct demand on the TVA system by almost 150 megawatts. Time-of-day rates for the residential, commercial, and industrial sectors would reduce demand by 616 MW; however, energy use would increase by 1,533 GWH. Finally, beneficial electrification options represent an increase in the demand for electric capacity by almost 400 megawatts.

FIGURE T8-77. **IRP Strategy Development – Option Choices**

Short-Term Decisions (1996-1999)	Long-Term Decisions (2000-2020)
SUPPLY	
• Build Bellefonte • Convert Bellefonte -Coal -Combined Cycle -Integrated Gasification Combined Cycle (IGCC) -IGCC w/Coproduction • Cancel Bellefonte • Cancel Bellefonte/ Browns Ferry Unit 1 • Cancel Bellefonte/ Browns Ferry Unit 1, Watts Bar Unit 2 • If Cancellation, Replace with -Combustion Turbines (CTs), Coal -CTs, Combined Cycle -CTs, IGCC with or without Coproduction -Purchased Power, Cogeneration, IPPs -Phased CT, CC, IGCC -Repower Fossil Units -Market-Based Options	• For Build, Cancel or Convert, Options Are: -CTs, Coal -Gas-Based -Clean Coal (IGCC) -Renewables
• Hydro Modernization • Storage Options	
• Defer Nuclear Units	• Then: -Build Nuclear -Cancel Nuclear -Convert Nuclear
ENVIRONMENT	
• Phase II Acid Rain -Reference Case (Low Cost) -Minimum Debt -Minimum CO_2 -Advanced Technology	• Phase II Acid Rain • CO_2 Offsets
• Wood Cofiring	

Defer the Decision to Complete the Nuclear Units

Another option is to defer the decision to either build, cancel, or convert some of the nuclear units to a later time period. This option has been specifically considered for Watts Bar Unit 2 and Browns Ferry Unit 1. For this preliminary analysis, the decision to build or cancel the nuclear units could be deferred to the year 2000. The deferral of the Bellefonte plant was not considered since the partnering option and conversion option are being considered at Bellefonte.

FIGURE T8-77. **IRP Strategy Development – Option Choices** *CONTINUED*

Short-Term Decisions (1996-1999)	Long-Term Decisions (2000-2020)
MARKETS	
• DSM -Low Rates -Low Cost -Low Penetration -High Penetration -Renewables -Low Income	• DSM • Beneficial Electrification
• Beneficial Electrification -Low Penetration -High Penetration • Off-System Sales • Distributed Generation • Fuel Switch to Natural Gas	
PRICING	
• Price Levels -Higher -Lower • Pricing Structure -Current Practice -Time-of-Day -Real Time -Block Structure	
TRANSMISSION	
• Efficiency Improvements • East-West Transmission -Capability	

Resource Strategies

The numerous nuclear, conversion, and supply- and demand-side resource options may be categorized into several different groups as outlined in *Figure T8-77*.

In *Figure T8-77*, options have been categorized according to those which can be implemented in the short term and those for the long term. The options have also been grouped by type, such as supply, environment, market, pricing, and transmission.

Strategies Evaluated

For this study, options have been chosen from *Figure T8-77* in order to develop strategies. The possible strategies are shown in *Figure T8-78*.

FIGURE T8-78. **Prospective Strategies in the IRP**

SUPPLY OPTIONS - NUCLEAR
- Build Bellefonte (BLN) Units 1 and 2, Browns Ferry (BFN) Unit 1, and Watts Bar (WBN) Unit 2
- Build BLN 1, BFN 1, WBN 2, and Cancel BLN 2
- Build BFN 1, WBN 2, and Cancel BLN 1 and 2
- Cancel All Four Units
- Convert BLN, Cancel WBN 2, BFN 1
  - -Combined Cycle (CC)
  - -Integrated Gasification Combined Cycle (IGCC)
  - -IGCC with Coproduction of Chemical Product (IGCC/P)
- Defer WBN 2, BFN 1
  - -Cancel BLN 1 and 2
  - -Convert BLN to CC
  - -Convert BLN to IGCC
  - -Convert BLN to IGCC/P
  - -Nuclear Partnership at BLN 1 and 2

OTHER SUPPLY OPTIONS

Short-Term	Long-Term
• Combined Cycle • Coal (Shawnee II) • Purchased Power, Cogeneration, Independent Power Producers (IPP)	• Clean Coal (IGCC) • Renewable (Wind,Biomass) • IPPs

DEMAND-SIDE MANAGEMENT (DSM)
- No DSM
- Low-Cost DSM Block (1000 MW)
- Low-and Medium-Cost Block (2000 MW)
- Low-Price Block (700 MW)

ENVIRONMENT
- Phase II Acid Rain Strategy
- Fuel Switch and Scrubber at Paradise Unit 3
- All Fuel Switch Strategy